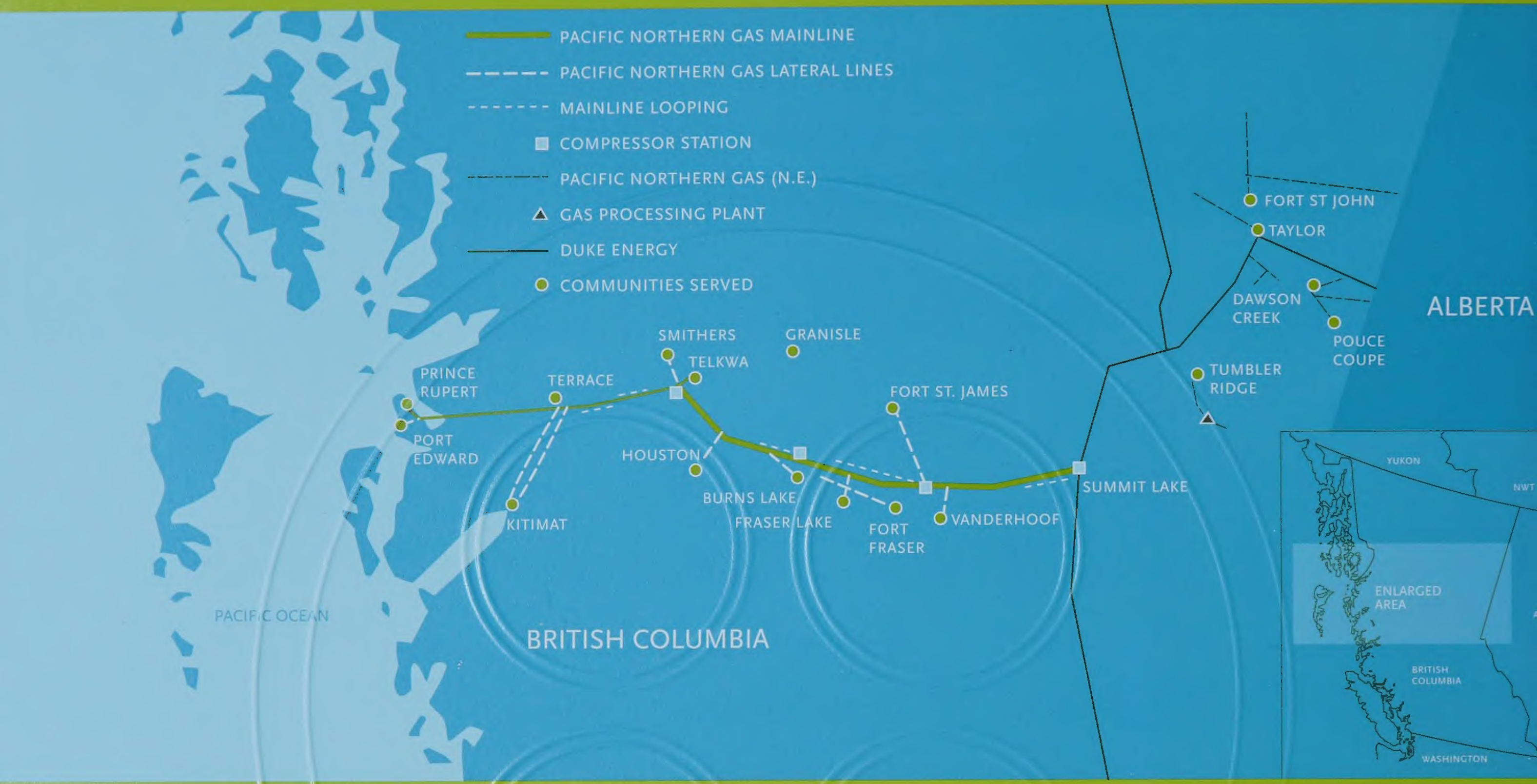
PACIFIC NORTHERN GAS LTD.
ANNUAL REPORT

2005

PACIFIC NORTHERN GAS



PACIFIC NORTHERN GAS LTD. DELIVERS NATURAL GAS TO CUSTOMERS IN WEST-CENTRAL BRITISH COLUMBIA, AND THROUGH ITS SUBSIDIARY, PACIFIC NORTHERN GAS (N.E.) LTD., TO CUSTOMERS IN THE PROVINCE'S NORTHEAST.

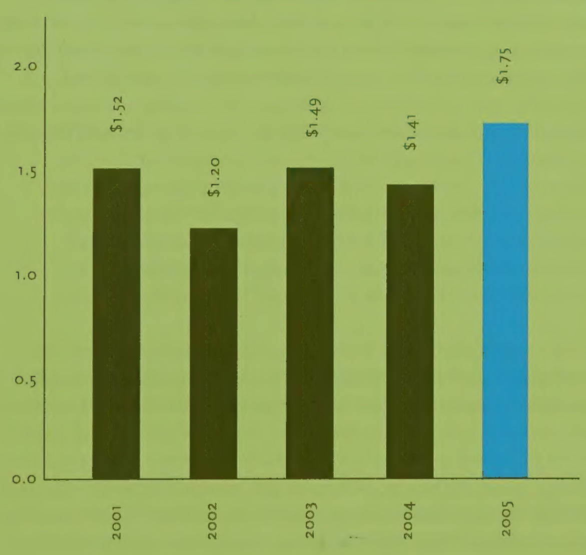
PACIFIC NORTHERN'S TRANSMISSION PIPELINE IS CONNECTED TO THE DUKE ENERGY SYSTEM NEAR SUMMIT LAKE, BRITISH COLUMBIA AND EXTENDS 587 KILOMETERS TO THE WEST COAST. SERVICE IS PROVIDED TO SOME 23 THOUSAND CUSTOMERS INCLUDING A NUMBER OF INDUSTRIAL OPERATIONS. IN ADDITION, PROPANE VAPOUR DISTRIBUTION IS PROVIDED IN THE COMMUNITY OF GRANISLE.

PACIFIC NORTHERN GAS (N.E.) SYSTEMS SERVE SOME 16 THOUSAND CUSTOMERS IN THE FORT ST. JOHN, DAWSON CREEK, AND TUMBLER RIDGE AREAS. GAS SUPPLY IS RECEIVED AT A NUMBER OF LOCATIONS WITHIN THE FORT ST. JOHN SERVICE AREA. IN THE DAWSON CREEK AREA THE COMPANY'S TRANSMISSION PIPELINE IS USED TO TRANSPORT GAS FROM THE DUKE ENERGY SYSTEM. IN TUMBLER RIDGE THE COMPANY OPERATES ITS OWN GAS PROCESSING PLANT.

PACIFIC NORTHERN'S HEAD OFFICE IS LOCATED IN VANCOUVER, BRITISH COLUMBIA. CUSTOMER CARE AND ADMINISTRATIVE FUNCTIONS ARE SUPPORTED FROM A REGIONAL CENTRE IN TERRACE. IN ADDITION, PERSONNEL RESPONSIBLE FOR CUSTOMER SERVICE AND SYSTEM CONSTRUCTION, OPERATION AND MAINTENANCE ARE STATIONED IN NINE COMMUNITIES LOCATED WITHIN THE COMPANY'S SERVICE AREA.

Years ended December 31	2005	2004	2003	2002	2001
Total energy delivered (TJ)	32 844	38 971	36 638	39 463	31 781
Income statement ($ in thousands)					
Net income	$6,660	$5,408	$5,668	$4,590	$5,715
Cash flow statement ($ in thousands)					
Operating cash flow	15,634	14,659	14,153	14,570	15,843
Additions to plant, property and equipment	6,753	11,276	5,406	5,965	3,761
Increase (decrease) in deferred charges	1,737	1,096	2,519	372	(1,345)
Balance sheet ($ in thousands)					
Total investment in utility plant	171,351	176,780	174,348	177,314	179,301
Total assets	215,210	207,657	206,414	212,506	207,113
Long term debt	76,560	81,440	85,827	90,224	79,539
Common shareholders' equity	77,692	73,950	71,522	68,966	74,345
Common share statistics					
Earnings per common share – Basic	$1.75	$1.41	$1.49	$1.20	$1.52
Earnings per common share – Diluted	$1.72	$1.38	$1.46	$1.18	$1.51
Dividends declared per common share	$0.80	$0.80	$0.80	$2.75	$0.00
Dividends declared per preferred share	$1.69	$1.69	$1.69	$1.69	$1.69
Common shares outstanding (thousands)					
Average for the year	3,620	3,597	3,583	3,553	3,548
End of year	3,626	3,604	3,584	3,579	3,548

Earnings Per Common Share



REPORT TO SHAREHOLDERS

ROY G. DYCE
PRESIDENT AND CHIEF EXECUTIVE OFFICER

THE COMPANY CONTINUED TO BE CHALLENGED IN 2005, ALTHOUGH THESE CHALLENGES WERE COUNTERBALANCED TO SOME EXTENT BY THE POTENTIAL FOR FUTURE DEVELOPMENT. WITH OUR ONGOING GOAL TO BUILD SHAREHOLDER VALUE, WE REMAIN COMMITTED TO THE JUDICIOUS MANAGEMENT OF OUR CURRENT OPERATIONS WHILE WE DEVISE AND EVALUATE NEW INITIATIVES. DETAILED BELOW ARE KEY SHAREHOLDER QUESTIONS AND THE STRATEGY CURRENTLY BEING IMPLEMENTED BY PACIFIC NORTHERN GAS THAT WE BELIEVE WILL HELP US MAINTAIN AND BUILD UPON OUR SUCCESS.

Q WHAT WERE THE FINANCIAL RESULTS FOR 2005?

A Pacific Northern Gas had positive financial and operational results in 2005, with net income of $6.7 million compared to $5.4 million for 2004, or an increase of 23.1 percent. This increase in net income was primarily due to an increase in the allowed rate of return approved by the British Columbia Utilities Commission and a reduction in unaccounted for gas losses compared to 2004.

Q NATURAL GAS COMMODITY PRICES CONTINUED TO BE HIGH AND VOLATILE THROUGHOUT 2005 – HOW HAS THIS AFFECTED GAS USAGE OF CUSTOMERS SERVED BY THE COMPANY?

A Over the last three years, the commodity price of natural gas has been highly volatile. The average price of natural gas in 2005 was approximately 30 percent higher than in 2004 and 26 percent higher than in 2003. When prices are high, fuel-switching and increased energy conservation can cause deliveries to decline, as other energy sources become more cost competitive. Average residential customer usage has indeed fallen over time due to a number of contributing factors including more efficient appliances replacing older units; warmer weather; and increased conservation efforts by individual customers. While we have no control over the market price of natural gas, we do have a gas price management program intended to mitigate price volatility for our customers. In addition, we encourage conservation by customers in order to improve the overall affordability of natural gas. Industrial customers, particularly those competing in world markets, can be more severely affected by high gas commodity prices.

Q ON AUGUST 30, 2005 METHANEX CORPORATION ANNOUNCED THE SHUTDOWN OF ITS METHANOL/AMMONIA COMPLEX IN KITIMAT – WAS THE COMPANY EXPECTING SUCH A SHUTDOWN AND HOW DID IT PREPARE FOR THIS MAJOR EVENT? WHAT ACTIONS ARE BEING TAKEN TO MINIMIZE THE IMPACT OF THE SHUTDOWN ON THE COMPANY'S CUSTOMERS AND SHAREHOLDERS?

A In response to Methanex temporarily closing its Kitimat methanol/ammonia complex for a year from July 1, 2000 to June 30, 2001, we significantly restructured our operations in late 2000 to decrease costs. At that time, we reduced our workforce by just over 40 percent. Since 2000, we have diligently monitored our operating and administrative costs, recognizing that Methanex could terminate its contract at any time.

Methanex's decision to close its Kitimat methanol/ammonia complex was due to the high price of natural gas in North America, compared to gas prices available elsewhere in the world. As natural gas was the feedstock for its manufacturing process, a significant increase in the commodity price made the plant uneconomical to operate. When Methanex announced the closure, spot prices for natural gas in British Columbia were in excess of $10 per gigajoule, compared to just over $5 per gigajoule a year earlier.

We will reflect Methanex's early contract termination payment of $23.3 million as revenue over the March 2006 to October 2009 period.

Now that the Methanex facility has closed, a thorough review of transmission system assets has been completed to determine which facilities are required on an ongoing basis to provide reliable, safe and efficient service to the remaining customers. Plant assets with a net book value of $5.1 million have been removed from rate base, with a proposed recovery from customers over a ten-year period.

ROBERT F. CHASE
CHAIR OF THE BOARD

Q THE COMPANY'S THIRD QUARTER REPORT TO SHAREHOLDERS STATED THAT KITIMAT LNG INC. IS IN THE PROCESS OF OBTAINING CERTIFICATES FOR ITS PROPOSED LIQUEFIED NATURAL GAS ("LNG") IMPORT, REGASIFICATION AND SEND-OUT TERMINAL TO BE LOCATED NEAR KITIMAT, B.C. WHAT OPPORTUNITY DOES THIS PRESENT TO PACIFIC NORTHERN GAS?

A In 2005, we commenced a preliminary study and investigation of a project that would require the Company to loop the main line transmission system from Kitimat to Summit Lake (the "KSL Project") to provide gas transportation services for the proposed LNG terminal. Completion of the KSL Project would significantly increase overall gas throughput as well as result in major cost benefits to our existing customer base. The KSL Project would involve reversing the flow of the pipeline and expanding pipeline capacity from the current 115 million cubic feet ("MMcf") per day to accommodate the delivery of 610 MMcf per day from the LNG terminal. Further details on the KSL Project are available on our website at www.png.ca.

Q THE COMPANY HAS RECEIVED APPROVAL FROM THE COMMISSION TO CONVERT THE COMPANY TO AN INCOME TRUST OWNERSHIP STRUCTURE. WHAT IS REQUIRED TO COMPLETE THIS CONVERSION AND WHEN WILL IT BE DONE?

A Throughout most of 2005, we sought the required approvals pursuant to the Utilities Commission Act to transfer ownership of the Company from the current common shareholders to an income trust ("the PNG Income Trust"). Under this plan, the PNG Income Trust would be owned by unit holders comprised of current shareholders, who would exchange their common shares for trust units, and new investors under an initial public offering. On October 28, 2005, the Commission approved our application to convert to an income trust. On November 18, 2005, the Commission requested that the Lieutenant Governor in Council of the Province of British Columbia approve the corporate amalgamation of the Company and its subsidiaries, which is a requirement before the conversion can proceed. As of the date of this report, Provincial approval is still pending.

We believe it is highly desirable to resolve the regulatory uncertainty arising from the termination of Methanex's transportation contract prior to commencing the conversion process. This uncertainty is directly related to the level of future revenues we will be permitted to recover from our remaining customers, which, in turn, will have a direct impact on cash flow and therefore the value of the Company as an income trust. The regulatory process to resolve this uncertainty is underway, and a resolution is expected in the second quarter of 2006. In addition, we are evaluating the efficiency of raising capital for the KSL Project under an income trust structure. The decision to proceed with the income trust and incur the significant transaction costs involved will be based on the best interests of all of our stakeholders, given the progress of the KSL Project, market conditions and other information available at the time.

THROUGHOUT 2005, THE COMPANY'S BOARD OF DIRECTORS CONTINUED TO PROVIDE STRONG GUIDANCE AND COUNSEL. ON BEHALF OF OUR SHAREHOLDERS, WE THANK YOU FOR ALL YOUR EFFORTS. WE WOULD ALSO LIKE TO THANK ROD SENFT AND TREVOR JOHNSTONE, WHO BECAME DIRECTORS IN 2003 AND RETIRED FROM THE BOARD DURING THE PAST YEAR, AND TO WELCOME NEW MEMBERS DIANE FULTON AND JANET WOODRUFF.

DETAILS OF THE ORGANIZATION AND WORKINGS OF THE BOARD OF DIRECTORS CAN BE FOUND IN THE MANAGEMENT INFORMATION CIRCULAR, WHICH IS MAILED TO ALL SHAREHOLDERS.

IN CLOSING, WE WISH TO THANK OUR EMPLOYEES FOR THEIR STRONG EFFORT AND DEDICATION THROUGHOUT 2005, AND OUR SHAREHOLDERS FOR THEIR ONGOING SUPPORT.

ROY G. DYCE
PRESIDENT AND CHIEF EXECUTIVE OFFICER
MARCH 2, 2006

DATE: FEBRUARY 16, 2006

This discussion should be read in conjunction with the enclosed audited consolidated financial statements of Pacific Northern Gas Ltd. (the "Company") for the year ended December 31, 2005. These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles. All amounts are stated in Canadian dollars unless otherwise indicated.

FORWARD-LOOKING STATEMENTS

Management's discussion and analysis contains certain forward-looking statements that are subject to risks and uncertainties that may cause the results or events predicted in this discussion to differ materially from actual results or events. In addition to the risks outlined in the Risk Management section at the end of the discussion, factors which could cause the results or events to differ include, but are not limited to: general economic conditions; gas commodity price volatility; decisions by regulators; seasonal weather patterns; the cost and availability of capital; and the ability of the Company to attract and retain quality employees. No assurance can be given that results, performance or achievement expressed in, or implied by, forward-looking statements within this disclosure will occur, or if they do, that any benefits may be derived from them. The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

BUSINESS OVERVIEW AND OUTLOOK

Pacific Northern Gas Ltd. and its wholly-owned subsidiary Pacific Northern Gas (N.E.) Ltd. (together the "Company") are natural gas distribution utilities operating within the Province of British Columbia, Canada.

The Company operates in two service areas, a transmission and distribution system in the west-central portion of northern British Columbia ("Western system") and a distribution system in northeastern British Columbia ("Northeast system"). The Northeast system is comprised of two divisions, the Fort St. John/Dawson Creek division and the Tumbler Ridge division.

The Company continues to monitor the competitiveness of its natural gas retail rates relative to alternative heating sources in its service area. Substantial increases in gas supply commodity prices over the last few years, combined with increases in the Company's delivery margins for residential, commercial and small industrial customers for its Western system, have led to retail gas rates which are similar to, or higher in the case of residential customers than comparable electricity rates.

The Company's strategic focus in 2006 will be to continue to pursue recapitalization under an income trust ownership structure, or a potential expansion of the transmission pipeline system to meet the requirements of a proposed LNG regasification facility near Kitimat in order to enhance shareholder value.

In 2005 the Company commenced preliminary study and investigation of a project to loop its main line transmission system from Kitimat to Summit Lake (the "KSL Project"). The KSL Project would be required to provide gas transportation services for the proposed Kitimat LNG Inc. liquefied natural gas ("LNG") receiving and regasification terminal to be located on the Douglas Channel approximately 15 kilometers southwest of Kitimat. If the terminal is constructed as planned, the Company will seek the necessary approvals to reverse the flow of its pipeline and expand pipeline capacity from the current 115 million cubic feet ("MMcf") per day to accommodate the delivery of 610 MMcf per day from the terminal.

Construction of the KSL Project is subject to a number of conditions including obtaining necessary permits for the Kitimat LNG Inc. terminal and the Company's pipeline expansion, acceptable commercial terms being negotiated between the Company and Kitimat LNG Inc., financing of both projects, and the securing of LNG supply by Kitimat LNG Inc. The Company can give no assurances that the construction of the terminal by Kitimat LNG Inc. or the expansion of the Company's pipeline will proceed.

On December 17, 2004, the Company filed an application with the British Columbia Utilities Commission ("Commission") seeking the approvals required pursuant to the Utilities Commission Act to transfer the ownership of the Company from the current common shareholders to an income trust called the "PNG Income Trust". Under the plan, the PNG Income Trust would be owned by unit

holders that would be comprised of the current shareholders that would exchange their common shares for units and new investors under an initial public offering of PNG Income Trust units. The application was reviewed at a public hearing before the Commission in May 2005. By decision dated September 9, 2005, the Commission granted conditional approval of the application, but included a reduction in the interest rate on subordinated debt compared to that applied for by the Company. On October 7, 2005, the Company applied for reconsideration and variance of the income trust decision, requesting the Commission approve the interest rates on subordinated debt as originally applied for by the Company. On October 28, 2005, the Commission approved the Company's request, and on November 18, 2005, requested that the Lieutenant Governor in Council of the Province of British Columbia approve the corporate amalgamation of the Company and its subsidiaries, a requirement before the conversion to an income trust can proceed. As of the date of this report, the Provincial approval is still pending.

The Company also believes it is highly desirable to resolve regulatory uncertainty, arising from the termination by Methanex Corporation of its transportation contract with the Company, prior to commencing the conversion process. The uncertainty, related to the level of future revenues the Company will be permitted to recover from its remaining customers, will have a direct impact on cash flow and therefore the value of the Company as an income trust. The regulatory process to resolve this uncertainty is underway, and a resolution is expected in the second quarter of 2006. In addition, the Company is evaluating the efficiency of raising capital for the KSL Project under an income trust structure.

In addition to the approval granted by the Commission and the provincial Order in Council, the approval of the shareholders of the Company, court approval, consent of the existing bondholders and acceptable market conditions will also be necessary for the conversion to an income trust to proceed.

The Company can give no assurances that the required approvals will be obtained, or that the conversion to an income trust ownership structure will occur.

OVERALL PERFORMANCE

Net income for 2005 was $6.7 million, compared with $5.4 million for 2004, or an increase of 23.1 percent. After providing for preferred share dividends, earnings per common share for 2005 were $1.75 compared with $1.41 for 2004. The increase in net income was primarily a result of an increase of $0.7 million in return on equity approved by the Commission and a reduction in unaccounted for gas losses, net of income taxes, of $0.5 million compared to 2004. Unaccounted for gas is the difference between the quantity of gas measured into the pipeline system and the quantity of gas delivered to customers, whether it is more or less. The impact of this unaccounted for gas loss, net of income taxes, was approximately $0.2 million in 2005, compared to $0.7 million in 2004. The increased return on equity resulted from approval of rates based on a higher deemed common equity proportion for the Western system compared to 2004.

Selected Annual Information

The following financial information has been prepared in accordance with Canadian GAAP and is shown in Canadian dollars.

	2005	2004	2003
(Dollar amounts in thousands, except per share and per GJ figures)			
Deliveries (TJ) –			
Sales – Western system	3 686	3 902	4 086
Sales – Northeast system	3 302	3 436	3 668
Transportation service – Western system	24 018	29 803	27 182
Transportation service – Northeast system	1 838	1 830	1 702
Total	32 844	38 971	36 638
Customers at period end	39,295	39,291	39,106
Weighted average cost of gas purchased ($ per GJ)	8.31	6.42	6.59
Operating revenues	$159,950	$137,755	$133,727
Operating margin, consisting of operating revenues less cost of sales	48,663	48,801	49,310
Net income	6,660	5,408	5,668
Basic earnings per common share	1.75	1.41	1.49
Diluted earnings per common share	1.72	1.38	1.46
Total assets	215,210	207,657	206,414
Total long-term financial liabilities	92,214	97,277	101,481
Dividends paid per common share	0.80	0.80	3.55
Dividends paid per preferred share	1.69	1.69	1.69

RESULTS OF OPERATIONS

Deliveries to residential and commercial customers in 2005 were lower by 0.1 petajoules, or 2 percent, compared to deliveries in 2004. Some of the reduction in deliveries was due to weather, which was approximately 6 percent warmer in 2005 than in 2004. Deliveries to residential and small commercial customers in 2005 were lower by 0.6 petajoules, or 9 percent, compared to the forecast volumes used to set customer rates. In 2004, deliveries were 8 percent lower than the forecast volumes used to set rates. The reduction in deliveries did not significantly impact net income due to the existence of a deferral account that captured the after-tax value of the revenue variance, amounting to $0.9 million ($1.2 million in 2004), arising from differences between actual and forecast volumes for residential and small commercial customers.

Operating revenues in 2005 increased to $160.0 million as compared with $137.8 million in 2004, largely due to the increase of $12.2 million in sales of gas surplus to the needs of the Company's sales customers ("off system gas sales"). Natural gas commodity prices, which are passed through to the Company's sales customers without mark-up, are very volatile and result in significant variability of the Company's reported operating revenues. Operating revenues in 2005 were significantly higher than 2004 and 2003 due to the higher commodity cost of gas.

Operating margin in 2005 decreased slightly to $48.7 million, as compared with $48.8 million in 2004. This decrease was due to anticipated reductions in expenses in 2005 that were used to determine customer rates.

NATURAL GAS DELIVERIES

Natural gas deliveries in 2005 totaled 32 844 terajoules* compared with 38 971 terajoules in 2004. A comparison of deliveries for the years 2005, 2004 and 2003 is provided in the following table:

Deliveries in terajoules	**2005**	**2004**	**2003**
Sales:			
Residential	3 135	3 279	3 464
Commercial	2 659	2 655	2 845
Small Industrial	689	778	825
Large Industrial	506	626	620
Total Sales	6 989	7 338	7 754
Transportation Service:			
Commercial	61	60	64
Small Industrial	2 887	2 958	2 764
Large Industrial – Methanex	20 497	25 952	23 820
Large Industrial – Other	2 410	2 663	2 236
Total Transportation Service	25 855	31 633	28 884
Total Deliveries	32 844	38 971	36 638

*The joule is a metric energy measurement unit. One gigajoule (GJ) is equivalent to 0.94782 British thermal units (BTU). One terajoule (TJ) equals one thousand GJ. One petajoule (PJ) equals one million GJ. In volumetric units, 1000 cubic meters is equivalent to 35.301 thousand cubic feet.

Transportation deliveries to large industrial customers decreased 20 percent from 2004 to 2005 resulting primarily from Methanex permanently shutting down its methanol/ammonia complex in Kitimat in November 2005. Deliveries to other large industrial customers declined in response to historically high gas commodity prices.

Deliveries to residential and commercial customers declined in 2005 by approximately 2.3 percent from 2004 levels, largely due to the weather being approximately 7 percent warmer in 2005 compared to 2004.

CUSTOMER ADDITIONS

In 2005, 420 new services were connected to the Company's distribution systems, compared with 345 in 2004. This increase in service additions is the result of continued strong economic activity in the Northeast system. Although 420 new services were connected, the Company experienced a net increase of only 4 customers. This is a result of 416 customers leaving the distribution system, primarily in the Company's Western service area. The continued net loss of customers in the Western service area reflects the generally poor economic conditions in this area.

There are few remaining candidates for conversion to natural gas in the existing building stock and limited opportunity remains to extend gas mains into unserviced rural areas in the Western service area.

NATURAL GAS SUPPLY

All of the Company's residential customers, most of its commercial customers and a number of its small industrial customers purchase gas from the Company at rates which include the gas commodity cost and the Company's cost of delivering gas to the customers' premises. The gas commodity cost paid by the Company to its gas suppliers is passed through without mark-up to customers.

The Commission reviews the gas commodity portion of the Company's rates on a quarterly basis to ensure close alignment with the prevailing market prices for natural gas. Any variances in gas commodity prices paid by the Company from those included in current retail rates are deferred for subsequent refund to or recovery from customers. To moderate the variability of the gas supply commodity prices paid, the Company uses financial instruments under a gas price management plan that is filed with the Commission on an annual basis.

A gas supply contracting plan is also prepared annually and filed with the Commission for review prior to finalizing annual gas purchase arrangements. The gas contracting plan is designed to ensure the Company has adequate gas supplies at reasonable prices to meet the requirements of its customers on the coldest day of the year, normally referred to as "the peak day". Contracted gas that is surplus to customer requirements is sold into other markets at prevailing market prices through off system sales. Most of the Company's contracted gas supply is produced in British Columbia.

The Company's large industrial customers, the majority of its small industrial customers and a few large commercial customers arrange for delivery of their gas supply requirements to the Company. These customers contract for gas transportation service on the Company's pipeline systems. Some of these customers also purchase gas from the Company to supplement their gas supply as may be required from time to time and subject to gas supply availability from the Company.

For 2005, approximately 36 percent of gas purchases were hedged pursuant to the Company's gas price management plan (for further information as of December 31, 2005 with regard to 2005 gas supply, see Financial Instruments and Other Instruments below).

Most of the Company's gas supply is comprised of the pooled gas stream available from the Duke Energy Gas Transmission ("Duke Energy") pipeline system. This includes all of the supply to the Company's transmission line serving its Western service area and approximately 74 percent of the supply for the Fort St. John and Dawson Creek service areas.

In addition to the supply from the Duke Energy system, the Fort St. John system incorporates two interconnections with Canadian Natural Resources Limited's West Stoddart Pipeline, providing 36 percent of the Fort St. John system's requirements. In Dawson Creek, approximately 7 percent of the required supply is received from a local producer of sweet (pipeline quality) gas at a point where its system intersects the Company's transmission line. In Tumbler Ridge, all of the gas supply is obtained in the form of raw gas production from a local producer and the Company operates its own gas processing facilities.

A long-term contract that expired on October 31, 2005 with CanWest Gas Supply Inc. accounted for about 52 percent of 2005 purchases. Other supplies included purchases under seasonal and spot gas supply arrangements. In 2006, the CanWest gas supply is being replaced with gas purchases under a number of short term, seasonal and spot gas supply arrangements. Short term gas supply contracts are in keeping with current industry practices.

LARGE INDUSTRIAL CUSTOMERS

The Company has firm transportation service and interruptible sales/service agreements with three of its large industrial customers: Methanex, West Fraser and Alcan Smelters and Chemicals Ltd. ("Alcan"). Methanex has served notice to terminate its agreement with the Company effective February 28, 2006, as discussed below.

The Company delivers gas to its other large industrial customer, British Columbia Hydro and Power Authority ("BC Hydro"), under an interruptible sales/service agreement for emergency electric power generation at BC Hydro's facility in Prince Rupert.

The large industrial customers produce commodities that are subject to world commodity price fluctuations. The Company's gas deliveries to these customers have been and may in the future be affected by their ability to continue operation during sustained periods of low commodity prices.

Deliveries to Methanex in 2005 accounted for approximately 62 percent of volumes delivered by the Company and approximately 7.6 percent of the Company's operating revenues. Transportation service to Methanex in 2005 was provided pursuant to an agreement that was set to expire on October 31, 2009, however on August 30, 2005, Methanex gave notice of its termination of the agreement. Under the terms of the agreement, Methanex is required to make a termination payment to the Company of approximately $23.3 million on February 28, 2006, the effective date of the termination. Under the terms of a negotiated settlement with registered intervenors and approved by the Commission on November 17, 2005, the termination payment will be recorded as an interest bearing credit deferral, and will be amortized into income over the period March 1, 2006 to October 31, 2009. An annual demand charge based on a firm toll of 50 cents per gigajoule applied over the term of the agreement. In addition, under the contract, Methanex supplied a portion of the Company's internal gas requirements equal to four percent of deliveries to Methanex. The contract also included a profit-sharing mechanism during periods of high methanol prices and relatively low natural gas prices. The profit-sharing mechanism did not result in any additional revenue to the Company in 2005.

Margin recovery in 2006 will be $10.4 million lower than in 2005 due to the Methanex contract termination. This reduction is offset by credit amortization of $5.6 million of the contract termination payment in 2006 resulting in a net margin reduction of $4.8 million. The Company has sought Commission approval in its 2006 revenue requirements application to recover the net $4.8 million margin reduction from its remaining customers. Depending on customer growth, it may be necessary to seek further rate increases commencing in 2010 after the contract termination payment has been fully amortized in rates.

The transportation service and sales contracts with West Fraser and Alcan are in effect through December 31, 2013 and October 31, 2007, respectively. The agreement with Alcan will continue to be in effect beyond October 31, 2007 unless Alcan or the Company gives notice of termination. During 2005, deliveries to West Fraser and Alcan accounted for 6.0 and 1.3 percent, respectively, of the Company's total gas deliveries and 1.3 and 0.5 percent, respectively, of operating revenues.

REGULATORY ACTIVITIES

The Company is subject to regulation under the Utilities Commission Act of British Columbia. The Commission regulates the business of the Company, including the construction and operation of major facilities, the issuance of securities, the determination of rates for the sale and transportation of gas and the terms and conditions of service.

In approving rates, the Commission must determine that the rates reflect a fair and reasonable charge for the nature and quality of service provided to customers. The rates should be sufficient to enable the Company to earn a fair and reasonable compensation for its services and a fair and reasonable return upon the value of its property.

The Commission determines customer rates using a fixed rate approach on the basis of forecasts of both the cost of service and the volumes of gas delivered through the transmission and distribution systems. The cost of service consists of the cost of purchased gas and the cost of transporting all gas delivered, including operating, maintenance and administrative expenses, depreciation of facilities, income and other taxes and a return on rate base. Rate base is the sum of the depreciated cost of property, plant and equipment that is used or useful in serving the Company's customers, plus a reasonable allowance for working capital. The Commission determines the allowable return on rate base after considering a variety of factors, including the degree of risk associated with the Company's business and the cost of capital.

Revenue requirements applications for all service areas are submitted to the Commission, generally on an annual basis. The Commission may consider these applications through a public hearing process (either oral or written), or through Commission staff supervised negotiations between the Company and its customers under negotiated settlement guidelines issued by the Commission. Settlements are subject to final approval by the Commission.

On December 17, 2004, the Company filed an application with the Commission seeking the approvals required pursuant to the Utilities Commission Act to transfer the ownership of the Company from the current common shareholders to the PNG Income Trust. The PNG Income Trust unit holders were expected to be comprised of current shareholders who would exchange their common shares for units as well as new investors via an initial public offering of PNG Income Trust units. The Commission reviewed the application through a public hearing process during May 2005.

In December 2004, the Company filed applications with the Commission for approval of new rates to take effect January 1, 2005 for all service areas. The revenue requirement applications for 2005 were considered by the Commission through a negotiated settlement process for the Western system and a written hearing process for the Fort St. John/Dawson Creek and Tumbler Ridge divisions.

The Commission issued its decisions on the 2005 revenue requirements applications on May 5, 2005 for the Fort St. John/Dawson Creek and Tumbler Ridge divisions. The 2005 allowed rate of return on common equity was 9.43 percent for the Fort St. John/Dawson Creek division and 9.68 percent for the Tumbler Ridge division, based on a deemed common equity component of rate base of 36 percent. The allowed rate of return on common equity includes a 40 basis point premium over the low risk benchmark utility rate of return (65 basis point premium for the Tumbler Ridge division).

The Commission on November 17, 2005 approved the settlement agreement reached between the Company and its customers respecting the Company's 2005 revenue requirements application for the Western system. The 2005 allowed rate of return on common equity was 9.68 percent including a 65 basis point premium over the low risk benchmark utility rate of return. Under the settlement agreement the interim rates effective January 1, 2005 were made permanent for all of 2005.

Western System

For 2005, the Commission continued its direction to defer the difference between actual operating margin from deliveries to Methanex, West Fraser, Alcan and B.C. Hydro and the forecast operating margin used by the Company in its revenue requirement application in an Industrial Customers Deliveries Deferral Account ("ICDDA"). The ICDDA increased 2005 net earnings by $0.3 million as actual 2005 deliveries to these customers were below forecast amounts. The Commission also accepted the Company's forecast of gas supply costs for 2005. Rate riders were approved in various amounts for 2005 to refund a credit balance accumulated in the gas purchase variance payable account. In 2005, the reduction in customer revenue from credit rate riders totalled $1.6 million, and was applied, on an after tax basis, to reduce the gas purchase variance payable account.

In its 2006 Revenue Requirements Application, the Company identified plant, property and equipment assets which would not be required on an ongoing basis to provide service to its customers, having regard to the closure of the Methanex Corporation plant in late 2005. The Company has requested that compressor facilities, pipeline loops and various other fixed assets with a net book value of $5.05 million be removed from rate base and transferred to a non-rate base, interest bearing deferral account effective December 31, 2005. The Company has applied for the deferral account to be amortized on a straight-line basis over ten years commencing in 2006. The ultimate recovery of this deferred charge is subject to a future decision of the Commission.

In 2004, a propane air plant that was no longer in service with an undepreciated value of $966,000 was removed from fixed assets and transferred to a deferral account, net of income taxes, for proposed future recovery from customers over a period of twenty years commencing in 2005. Under the terms of the 2005 negotiated settlement, $165,000 of the amount deferred in 2004 was written off

in 2005 and not collected in customer rates. A further $242,000 was transferred to plant in service, and the remaining balance of the deferral, amounting to $445,000 net of income taxes and salvage, will be amortized into customer rates over a ten year period beginning in 2005.

The 2006 revenue requirements application for the Western system was filed with the Commission in November 2005. The application sought approval of increased delivery charges and increased gas supply commodity charges, effective January 1, 2006. Approximately 95 percent of the gas delivery charge increase was due to the termination of the Methanex contract. In 2006, the Company applied for a deemed common equity ratio of 40 percent. The Commission approved interim gas delivery charge increases effective January 1, 2006 applying the requested deemed 40 percent common equity ratio. The permanent gas delivery rates will be determined under a negotiated settlement process, scheduled to commence in March 2006.

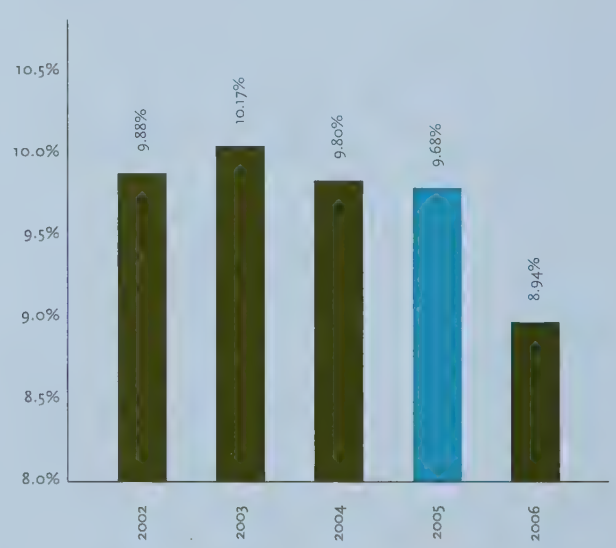
The Commission accepted the gas supply commodity charge adjustments applied for by the Company, effective January 1, 2006. The permanent gas supply commodity charges effective January 1, 2006 are almost equal to the gas supply charges approved by the Commission as of October 1, 2005 for the residential and commercial customers. Small industrial, seasonal and natural gas vehicle customer classes saw gas supply commodity charge increases compared to those in effect as of October 1, 2005.

The forecast 2006 residential and commercial deliveries contained in the 2006 revenue requirements application for the Western system are approximately 5 percent higher than actual gas deliveries to these customer classes in 2005. Deliveries to small industrial customers are projected to be approximately 2 percent lower in 2006 compared to actual gas deliveries in 2005.

Prior to the commencement of each calendar year, the Commission resets the allowed rate of return on common equity for each of the Company's regulatory divisions by a formula which uses, among other things, a consensus forecast of yields on 10-year Government of Canada bonds for the forthcoming year. Largely as a result of the lower 10-year bond yields which were in effect in the latter part of 2005 relative to the same period in 2004, the consensus forecast of 2006 10-year bond yields declined relative to the late 2004 consensus forecast of 10-year bond yields for 2005. Through application of the formula the approved rates of return on common equity for the Company have declined. In December 2005, the Commission confirmed that the formula resulted in an allowable 8.29 percent rate of return for a low risk benchmark utility in 2006. For the Company, a return on equity risk premium of 65 basis points applies to the Western system resulting in an allowable rate of return on common equity of 8.94 percent for 2006.

The Commission is reviewing an application made by another utility in 2005 to review and revise the formula used to calculate the rate of return on common equity for public utilities regulated by the Commission. A decision on that application could impact the determination of the 2006 rate of return on common equity applicable to the Company.

PNG West Allowed Return on Common Equity 2002-2006



Fort St. John / Dawson Creek Division

The Commission accepted the Company's forecast of gas supply costs for 2005. Rate riders were approved for 2005 to refund credit balances recorded in the gas purchase variance recoverable account at December 31, 2004 over a period of three years. In 2005, customer

revenue from rate riders totalled $0.1 million, which was applied, on an after tax basis, to reduce the gas purchase variance payable account.

The Fort St. John/Dawson Creek 2006 revenue requirements application, filed in December 2005, sought Commission approval to increase both the gas delivery charge component of its gas rates as well as the gas commodity charges. The Commission approved interim delivery charges effective January 1, 2006 at the level applied for which includes a deemed common equity of 36 percent and an allowable return on common equity of 8.69 percent for 2006. The gas supply commodity charge increases were approved as filed on a permanent basis. In total, the interim rate increases effective January 1, 2006 are higher by approximately 10 percent for both residential and small commercial customer classes compared to rates in effect as of December 31, 2005.

Tumbler Ridge Division

The Tumbler Ridge 2006 revenue requirement application was filed with the Commission in December 2005. The application sought Commission approval to increase the gas delivery charge component of rates effective January 1, 2006 as well as the gas commodity charges. The requested increases in the gas delivery charge component are primarily due to increased operating costs, including increases in the cost of gas required for operating the Company's processing plant. The resulting rate increases were approximately 11 percent for residential and small commercial customers relative to rates in effect on December 31, 2005.

A negotiated settlement process for the Fort St. John/Dawson Creek and Tumbler Ridge divisions' 2006 revenue requirements applications is scheduled to commence in March of 2006.

SUMMARY OF QUARTERLY RESULTS

The following financial information has been prepared in accordance with Canadian GAAP and is shown in Canadian dollars.

	2005				
	Mar. 31	June 30	Sept. 30	Dec. 31	Total
(Dollar amounts in thousands, except for per share data)					
Operating revenues	47,798	30,293	32,238	49,621	159,950
Net income (loss)	3,984	137	(772)	3,311	6,660
Earnings (loss) per common share – basic	1.08	0.02	(0.24)	0.89	1.75
Earnings (loss) per common share – diluted	1.06	0.02	(0.24)	0.88	1.72

	2004				
	Mar. 31	June 30	Sept. 30	Dec. 31	Total
Operating revenues	43,584	28,245	25,169	40,757	137,755
Net income (loss)	3,848	317	(1,427)	2,670	5,408
Earnings (loss) per common share – basic	1.05	0.06	(0.42)	0.72	1.41
Earnings (loss) per common share – diluted	1.03	0.06	(0.42)	0.71	1.38

The Company's natural gas distribution business is very seasonal, with higher sales in the colder winter months and lower sales in warmer months as a result of a substantial portion of its gas sales being used for space heating purposes. As a result, the Company earns the majority of its net income in the first and fourth quarters of its fiscal year and often realizes losses in the other quarters.

LIQUIDITY

Contractual Obligations

	Payments Due by Period as of December 31, 2005				
	Total	Less than 1 year	1 - 3 years	4 - 5 years	After 5 years
($ in thousands)					
Long Term Debt	81,440	4,880	9,760	9,960	56,840
Purchase Obligations	48,526	45,451	2,084	991	0
Total Contractual Obligations	129,966	50,331	11,844	10,951	56,840

The purchase obligations in the table above represent commitments by the Company to purchase natural gas or transportation service from third parties. The Company enters into a number of arrangements to purchase gas on a seasonal basis for resale to its customers during the heating season.

Funding Requirements

The Company's capital expenditures, working capital needs, dividend payments and debt repayments are funded from a combination of sources. During 2005, the primary sources of funding were $11.8 million of cash generated from operations, and a draw of $4.1 million under an operating line of credit.

The Company purchases gas for resale to its core market customers and passes through the commodity cost of gas to those customers without mark-up. The rates charged to core market customers are based, in part, on projected gas supply prices. The Company's liquidity requirements are affected by delays between increases or decreases in the cost of gas purchased by the Company and regulatory approval of rate adjustments to reflect the cost increases or decreases.

Financial Ratios

At the end of 2005, interest coverage using earnings before interest, income taxes, depreciation, and amortization was 3.619 times compared to 3.262 times in the prior year improving as a result of both higher earnings and a reduction in interest expense.

FUNDING COSTS

Interest Expense

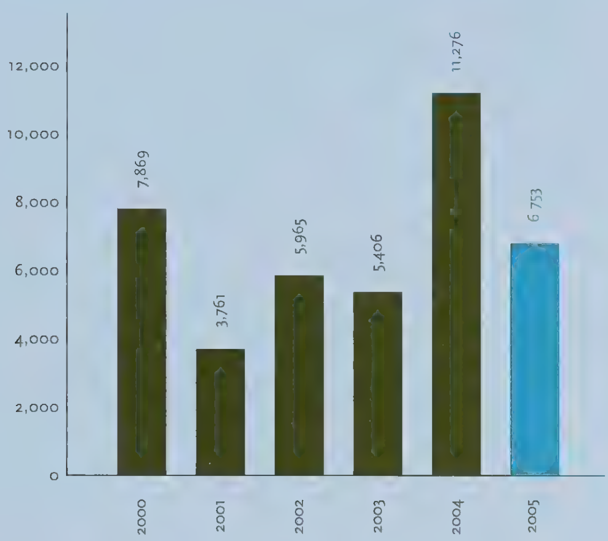
	2005	2004	2003
(Dollar amounts in thousands, except percent figures)			
Long-term interest expense	7,083	7,564	7,536
Short-term interest expense	481	450	573
Total	7,564	8,014	8,109
Effective blended cost of debt (%)	8.7	9.0	8.7

The slight decrease in the effective blended cost of debt is due to higher average short term debt balances as a proportion of total debt. The interest rate on short term debt is lower than the interest rate on the Company's long term debt.

CAPITAL EXPENDITURES

Total capital expenditures in 2005 were 40 percent or $4.5 million lower than those incurred in 2004 and 1.5 percent below the average level of expenditures for the last five years. Capital expenditures in 2004 included $4.4 million that was out of the ordinary resulting from a requirement to directionally drill under the Salmon River to replace a duel underwater transmission system crossing. The majority of the capital expenditures in 2005 were for maintenance capital as well as customer additions to the distribution system on the Northeast system.

Capital Expenditures 2000-2005 ($000s)



	2005	2004	2003
($ in thousands)			
Transmission system	3,103	7,032	2,310
Distribution system	2,233	2,905	2,356
Processing plant	112	80	41
Other	1,305	1,259	699
Total	6,753	11,276	5,406

Planned capital spending in 2006 is primarily directed toward distribution mains and services as well as transmission mainline rehabilitation, and is forecast to be approximately $7.9 million. Contractual commitments have yet to be made for major planned capital expenditures for 2006. These capital expenditures will be funded from cash flow from operations.

CAPITAL RESOURCES

Composition of Capital Structure (Percent)

At December 31	2005	2004	2003
Preferred shareholders' equity	2.9	2.9	2.9
Common shareholders' equity	44.6	43.3	42.2
Short-term debt	5.8	3.5	1.7
Long-term debt, including current portion	46.7	50.3	53.2
	100.0	100.0	100.0

For rate determination purposes the Company is permitted to earn a return on its invested capital to the extent of its approved rate base. Rate base is composed of the depreciated book value of fixed assets, plus unamortized deferred charges, plus an allowance for working capital, less deferred income taxes. The Commission sets customer rates at a level that is intended to allow the Company to earn its allowed rate of return on common equity. Interim rates for 2006 are based on 36 percent of rate base for the Fort St. John / Dawson Creek and Tumbler Ridge divisions and 40 percent for the PNG West division.

Equity

The book value of the common shares at December 31, 2005 was $21.43 per share, compared to $20.52 per share at December 31, 2004.

The Company's preferred shares are currently rated Pfd-3(low) by Dominion Bond Rating Service ("DBRS"). On September 1, 2005, DBRS placed the ratings of the Company's preferred shares under review with negative implications, following the announcement of the termination of the Methanex agreement.

On March 11, 2005, the Company filed a prospectus for the public offering of 1,338,477 common shares of the Company owned by Tricor Acquisition (STP) Inc. ("Tricor"), at a price of $19.40 per common share, for gross proceeds of approximately $26 million. The common shares offered by Tricor represented 37 percent of the Company's outstanding common shares and 100 percent of Tricor's interest in the Company. The transaction was subsequently completed on April 12, 2005. The Company did not sell any newly issued common shares as part of this offering and did not receive any of the proceeds from the sale of the common shares by the selling shareholder.

Dividends

Preferred dividends totaling $1.6875 per share were paid in 2005, the same as in 2004.

Common dividends totaling $0.80 per share were paid in 2005, compared to $0.80 per share paid in 2004 and $3.55 in 2003. The 2003 dividends included a special dividend of $2.75 per common share paid in January 2003. The special dividend was declared following the issuance of $15 million of new longer term financing in December 2002, and resulted in a capital structure that was more closely aligned with that approved by the Commission.

A total of $3.2 million preferred and common dividends were paid in 2005, compared to $3.2 million paid in 2004 and $13.1 million paid in 2003.

Short-term Debt

Commencing in January 2005, the Company arranged new credit facilities which included a $20 million operating line and a $15 million risk management facility. The operating line is subject to borrowing base requirements and financial covenants which may act to restrict the amount the Company can borrow under the operating line. The operating line of credit and the risk management facility were collateralized by the pledge of a $40 million debenture and a charge on certain accounts receivable and inventories.

As a result of seasonality in operations, marginable receivables and other assets are significantly reduced in the second and third quarters compared to the winter heating season, thus constraining availability of the operating line of credit. At December 31, 2005, the amount available under the facility was approximately $18.5 million, of which $10.2 million had been drawn. The Company provided covenants to its operating lender, all of which were complied with during 2005.

Long-term Debt

The Company's secured debentures are currently rated BBB (low) by DBRS. On September 1, 2005, DBRS placed the ratings of the Company's secured debentures under review with negative implications, following the announcement of the termination of the Methanex agreement.

Off Balance Sheet Arrangements

As of December 31, 2005, the Company had no off-balance sheet arrangements, other than the natural gas hedging contracts described in Financial and Other Instruments below.

Transactions with Related Parties

The Company had no transactions with related parties during 2005 or 2004.

FOURTH QUARTER

The following table compares the results for the fourth quarters of 2005 and 2004:

	Q4 2005	Q4 2004	Percent Change
(Dollar amounts in thousands, except per share and per GJ figures)			
Deliveries (TJ) – Sales	2 191	2 385	(8.1)
Transportation service	3 293	8 185	(59.8)
Total	5 484	10 570	(48.1)
Customers at period end	39 295	39,291	0.0
Weighted average cost of gas purchased ($ per GJ)	10.20	7.34	39.0
Operating revenues	49 621	40,757	21.7
Operating margin, consisting of Operating revenues less cost of sales	14 259	14,739	(3.3)
Income before income taxes	5,042	4,480	12.5
Net income	3,311	2,670	24.0
Operating cash flow	5,279	5,447	(3.1)
Basic Earnings per common share	0.89	0.72	23.6
Dividends paid per common share	0.20	0.20	–

Net income for the quarter ended December 31, 2005 was $3.3 million, compared with $2.7 million for the quarter ended December 31, 2004. After providing for preferred share dividends, earnings per common share in the fourth quarter of 2005 were $0.89, compared with $0.72 for the quarter ended December 31, 2004. Net income in the fourth quarter of 2004 was reduced by $0.4 million due to unaccounted for gas losses.

Operating revenues in the fourth quarter of 2005 increased to $49.6 million as compared with $40.8 million in the same period in 2004. The increase in operating revenue in the fourth quarter is attributed to an increase of $5.1 million in revenue from off-system gas sales. In addition, revenues from residential and commercial customers were $3.5 million higher and revenues from deliveries to industrial customers were $0.2 million higher compared to the corresponding period in 2004. The increase in revenues is primarily due to the increase in gas supply costs embedded in sales customers' rates compared with the corresponding period in 2004.

Operating margin in the fourth quarter of 2005 decreased to $14.3 million, compared to $14.7 million in the corresponding period in 2004, due to lower customer deliveries in the fourth quarter of 2005 relative to the same period in 2004.

Capital expenditures in the fourth quarter of 2005 were $3.0 million, compared to $5.2 million in the comparable period in 2004. Expenditures in the fourth quarter of 2004 included $2.7 million relating to the Salmon River directional drill.

PROPOSED TRANSACTIONS

Kitimat Summit Lake Looping Project

On October 18, 2005 the Company engaged two international banks as co-arrangers for the project financing of the proposed KSL project. These banks were also concurrently engaged by Kitimat LNG Inc. as co-arrangers for the project financing of the proposed regasification terminal.

In 2005 the Company incurred costs of $0.9 million associated with the KSL Project. Kitimat LNG Inc. is obligated to fund $0.4 million of this amount under an agreement with the Company. If construction of the Kitimat LNG Inc. terminal proceeds, the deferred costs will be transferred to construction work in progress and the Company will be required to refund all of the funding provided by Kitimat LNG Inc.

In the event the terminal is not constructed, the Company will seek recovery of the deferred costs in future customer rates. In the event the Company is permitted to recover any deferred KSL preliminary development costs in its future rates, the recovery of costs will be shared on a pro rata basis with Kitimat LNG Inc. in proportion to the funding provided by each party.

Construction of the KSL Project is subject to a number of conditions including obtaining necessary permits for the Kitimat LNG Inc. terminal and the Company's pipeline expansion, acceptable commercial terms being negotiated between the Company and Kitimat LNG Inc., financing of both projects, and the securing of LNG supply by Kitimat LNG Inc. The Company can give no assurances that the construction of the terminal by Kitimat LNG Inc. or the expansion of the Company's pipeline will proceed.

Second Application for Approval of an Income Trust Ownership Structure

On December 17, 2004, the Company filed an application with the Commission seeking the approvals required pursuant to the Utilities Commission Act to transfer the ownership of the Company from the current common shareholders to the PNG Income Trust. Under the plan, the PNG Income Trust would be owned by unit holders that would be comprised of the current shareholders that would exchange their common shares for units and new investors under an initial public offering of PNG Income Trust units. The application was reviewed at a public hearing before the Commission in May 2005. By decision dated September 9, 2005, the Commission granted conditional approval of the application, but included a reduction in the interest rate on subordinated debt compared to that applied for by the Company. On October 7, 2005, the Company applied for reconsideration and

variance of the income trust decision, requesting the Commission approve the interest rates on subordinated debt as originally applied for by the Company. On October 28, 2005, the Commission approved the Company's request, and on November 18, 2005, requested that the Lieutenant Governor in Council of the Province of British Columbia approve the corporate amalgamation of the Company and its subsidiaries, a requirement before the conversion to an income trust can proceed. In addition to the approval granted by the Commission and the provincial Order in Council, the approval of the shareholders of the Company, court approval, consent of the existing bondholders and acceptable market conditions will also be necessary for the conversion to an income trust to proceed. The Company can give no assurances that the required approvals will be obtained, or that the conversion to an income trust ownership structure will occur.

Critical Accounting Estimates

Operating revenues include natural gas sales that are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading date to the end of the reporting period for such operating revenues. These estimates are made assuming normal consumption patterns, which may differ from actual consumption patterns. The estimates of unbilled operating revenue comprise 6 percent of the Company's operating revenues for 2005. Through future meter readings, the usage estimates are replaced with actual delivered volumes, which become reflected in the Company's financial results at that time.

CHANGES IN ACCOUNTING POLICIES INCLUDING INITIAL ADOPTION

Changes Adopted in 2005

Disclosure by Entities Subject to Rate Regulation
Effective December 31, 2005, the Company adopted the new Accounting Guideline AcG-19, Disclosure by Entities subject to Rate Regulation, which applies to years ending on or after December 31, 2005. AcG-19 provides guidance about certain aspects of the disclosure and presentation of information of entities providing services or products for which customer rates are established or approved by a regulator. The objective is to ensure that financial statement users are better informed about the existence, nature and effects of all forms of rate regulation. If rate regulation has an impact on the accounting treatment of a transaction, the entity should make mention of it and provide additional information about the impact on its financial statements.

New Accounting Standards

New accounting standards will be in effect for fiscal years beginning on or after October 31, 2006 for hedge accounting, recognition and measurement of financial instruments and disclosure of comprehensive income. The Company is currently investigating the impact of these new standards.

FINANCIAL INSTRUMENTS AND OTHER INSTRUMENTS

The Company utilizes natural gas commodity hedging contracts in order to manage the volatility inherent in the prices of its natural gas purchases. It also utilizes interest rate hedging contracts to reduce the volatility of the interest expense associated with its floating rate debt instruments. As of December 31, 2005 the Company had no interest rate hedging contracts outstanding.

During the first quarter the Company completed its annual gas contracting and gas supply price management plan and filed it with the Commission for review and acceptance. In response to discussions with Commission staff, the plan was slightly modified in early June. The Commission accepted the modified plan later in June 2005. The plan called for gas price hedging, covering purchases over the period November 1, 2005 through October 31, 2006, to be completed in stages over the June to September 2005 period. Each hedging transaction was approved by the Company's price management plan committee and reported to the Commission.

At December 31, 2005, the Company had outstanding fixed price contracts, natural gas swap contracts, and call options relating to natural gas supply as follows:

Financial Instrument	Notional Quantity (GJ's)	Percent of Annual Gas Purchases	Delivery Period	Price Range (per GJ)	Estimated Fair Value Receivable (Payable) ($000's)
Fixed price contracts	450 000	4.6	Jan. - Mar. 2006	$5.83 to $10.00	($167)
Natural gas swap contracts	1 193 000	12.1	Jan. - Oct. 2006	$7.85 to $10.60	$1,670
Call options	1 219 500	12.3	Jan. - Mar. 2006	Caps from $10.00 to $15.00	$633
Total	2 862 500	29.0			$2,136

The fair value reflects the estimated amounts that the Company would receive at December 31, 2005 to terminate the fixed price contracts, natural gas swap contracts or call options, based on the estimated net cash flows under the terms of each contract.

These estimated fair market values have no impact on earnings due to the regulated nature of the Company's operations. Based on the current regulatory process, any gains or losses arising from utility related financial instruments would be treated as part of the cost of service.

At December 31, 2004, the Company had outstanding fixed price contracts and collar contracts relating to natural gas supply as follows:

Financial Instrument	Notional Quantity (GJ's)	Percent of Annual Gas Purchases	Delivery Period	Price Range (per GJ)	Estimated Fair Value Payable ($000's)
Fixed price contracts	3 219 000	22.8	Jan. - Oct. 2005	$6.27 to $9.87	($3,855)
Collar contracts	716 850	5.1	Jan. - Feb. 2005	$8.22 to $10.25	($1,406)
Total	3 935 850	27.9			($5,261)

The fair value reflects the estimated amounts that the Company would pay at December 31, 2004 to terminate the fixed price contracts or collar contracts based on the estimated net cash flows under the terms of each contract.

Natural gas prices for 2006 for gas purchases by the Company, based on forward gas prices as at February 15, 2006, are forecast to be approximately 2 percent ($0.16 per GJ) lower than the actual corresponding prices in 2005.

DISCLOSURE CONTROLS AND PROCEDURES

The Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in the rules of the Canadian Securities Administrators) and concluded that the Company's disclosure controls and procedures were effective as of December 31, 2005 and in respect of the 2005 year end reporting period.

OUTSTANDING SHARE DATA

At February 16, 2006, there were 200,000 preferred shares and 3,626,180 common shares outstanding. The common shares are the only issued voting securities of the Company, and it has no securities outstanding which may be converted into voting or equity securities.

RISK FACTORS

Industrial customer concentration and potential for termination of contracts

In 2005, 70 percent of energy deliveries were made to the Company's three largest industrial customers, compared to 75 percent in 2004. The Company's contract with Methanex was terminated effective February 28, 2006. The Company's contract with West Fraser expires in 2013 and may be terminated prior to that date upon payment of an amount described in the contract, or without payment in certain circumstances. Alcan, whose deliveries account for

approximately 1.3 percent of annual deliveries, has a firm gas transportation agreement that would expire October 31, 2007 if either party gives twelve months notice of termination by October 31, 2006. The Company's ability to negotiate new contracts and to renegotiate existing contracts could be impacted by factors it cannot control, including reduced demand due to higher gas prices, the financial strength of major customers and the availability and price competitiveness of alternative energy sources. The risk of non-performance by one or more of the large industrial customers may be analyzed and managed, but it cannot be entirely eliminated.

The Company's service area is economically dependent upon industrial customers for its economic stability. These customers produce commodities that are subject to world commodity fluctuations. Gas deliveries to these customers have been and may in the future be affected by their ability to continue to operate during sustained periods of low commodity prices. A prolonged decline in a sector affects all customer classes. For example, in the Western region many of the Company's industrial customers are involved in the forest sector. A prolonged decline in the forest sector could negatively impact gas deliveries to a lumber mill, as well as negatively impacting delivery requirements of commercial and residential customers who directly or indirectly provide services to that mill.

Commodity Price and Supply Risk

Over the last three years, the commodity cost of natural gas has been highly volatile. The average cost of natural gas in 2005 was approximately 30 percent higher than in 2004 and 26 percent higher than in 2003. When prices are high, the prospects of fuel-switching and increased energy conservation pose a risk, as other energy sources can become more cost competitive. Fluctuations in the price of natural gas may increase the Company's working capital financing requirements and related costs for accounts receivable, and may give rise to higher bad debt costs.

Adequate supplies of natural gas may not be available to satisfy committed obligations as a result of economic events, natural occurrences, and/or failure of a counter-party to perform.

Usage Risks

Natural gas competes with other forms of energy available to the Company's customers and end-users, including electricity, wood and coal and, in the case of certain industrial customers, wood waste. The primary competitive factor is price. Changes in the availability or price of natural gas and other forms of energy, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors affect the demand for natural gas in the Company's service areas. In addition, because electricity prices in British Columbia for residential and certain other customer classes have been set based primarily on the historical average cost of production, they have remained artificially low compared to market priced natural gas. Over time, this distortion in pricing signals may affect decisions by British Columbia consumers, potentially decreasing the use of natural gas by customers.

Over the past several years the average amount of natural gas consumed by residential customers has declined. This decline is attributable to a number of factors, including the replacement of older heating equipment by newer, more efficient equipment, more energy efficient housing, and energy conservation measures in response to higher gas prices and poor economic conditions in the Western region.

Regulatory Risk

The Company's asset base is subject to regulation by the Commission (see "Regulatory activities"). Changes in the regulatory environment may be beyond the Company's control and may impact the viability of the assets, including the Company's ability to sustain or increase its profitability.

As part of the regulatory process, the Company maintains a number of deferral accounts including, without limitation, a gas cost variance account, the rate stabilization adjustment mechanism account and accounts for pipeline repair and rehabilitation.

The gas cost variance account is utilized to record variances in the Company's actual purchase cost of gas relative to the gas supply cost recovery charges included in customers' rates. At times, the gas supply cost recovery charges included in customers' rates can be below the actual purchase cost of gas resulting in a significant balance in the account which must be recovered from customers in future rates.

The Company's rates are set on the basis of forecast gas deliveries using normal heating degree-days. To the extent that actual degree-days are less than normal (that is, the weather is warmer than normal), revenues may be less than forecast. The revenue for residential and small commercial customers is protected by the rate stabilization adjustment mechanism deferral account approved by the Commission in 2003 to record differences between forecast and actual deliveries. When deliveries to customers are less than forecast, there may be significant balances in the account which are subject to recovery in future rates to customers.

The Commission requires the Company to record certain temporary pipeline repair and rehabilitation costs in deferral accounts for amortization into customer rates over a period of ten years on the basis that the customers benefit from such expenditures over that period of time.

The recovery of the Company's accumulated deferral accounts has an impact on liquidity requirements. Recovery of the deferral accounts through rates charged to customers is dependent upon regulatory approval and the ability to set rates high enough to recover such balances while maintaining the competitiveness of retail gas prices, and is therefore at risk.

Liquidity, Cash Flow, and Capital Availability Risks

The Company's credit facilities include a $20 million operating line and a $15 million risk management facility. The operating line is subject to borrowing base requirements which may restrict the amount that the Company can borrow under the line at any point in time. In addition, the credit facilities are also subject to financial covenants that may act to restrict the amount that can be borrowed under the operating line. The credit facilities also contain a restriction on payments that may have the effect of reducing or eliminating the dividends that the Company can pay in the absence of access to new long term debt.

The Company is currently relying on operating cash flow to fund capital expenditures, scheduled amortizations of long term debt and payment of dividends. While operating cash flow is currently adequate for those purposes, there is no assurance that it will be in the future. Any constraint on the Company's ability to raise capital, including a credit downgrade, may negatively impact its investment activities, capital expenditures and hedging program.

Facility and Insurance Risk

The Company carries on business in a geographic area of British Columbia where a large portion of its pipeline transmission system is located in extremely difficult terrain and where outages have, from time to time, been experienced in the past. Depending on circumstances, such outages may result in loss of revenues or increased maintenance or capital costs.

The Company maintains insurance against exposures to the physical loss of its pipeline, compressors and other above ground facilities as well as loss of earnings insurance relating to revenues from its large industrial customers. Based on past insurance claims for damage to the pipeline caused by slides, washouts, and other natural events, the Company's deductibles have increased. Depending on the number and severity of future outages, the financial impact on the Company could be material.

Environmental and Safety Risks

The Company is required to comply with existing environmental laws and regulations. It is possible that increasingly strict environmental laws, regulations and enforcement policies, and potential claims for damages and injuries to property, employees, other persons and the environment resulting from current or discontinued operations, could result in substantial costs and liabilities in the future. In particular, the Company could be exposed to significant operational disruptions and environmental liability in the event of an accident involving natural gas. The Company believes it has taken all reasonable and prudent steps to minimize its exposure in the case of safety or environmental incidents.

The Government of Canada ratified the Kyoto Protocol on December 17, 2002. No final decisions have been made on the targets, measures and regulations for industry sectors and companies to ensure compliance, and development of the methodology is currently in flux. It is not possible at this time to measure the extent of the impact of the Kyoto Protocol on the Company.

Derivatives Risk

The Company uses derivative and other financial instruments in connection with the management of gas supply prices and interest rates. Forward, future, swap, fixed price and option contracts are used to manage the impact of market fluctuations on assets, liabilities or other contractual commitments. The Company could, however, incur financial losses in the future as a result of market or price volatility. Furthermore, because the valuation of these financial instruments can involve estimates, changes in the assumptions underlying these estimates can occur, changing the Company's valuation and potentially resulting in financial losses. This risk could affect the Company's liquidity, and regulatory approval would be required for the recovery of related costs through future rate adjustments.

OTHER

Litigation

Pacific Northern Gas (N.E.) Ltd. was involved in a legal dispute with a customer over the payment for gas transported to the customer. The dispute related to the customer's obligation to supply its own gas for transportation to their facilities, or failing that, to pay for gas delivered to those facilities. On September 29, 2005 a settlement was negotiated between the parties, and payment of the agreed amount was received on October 11, 2005. There was no impact on net income in 2005 arising from the settlement of the dispute.

Additional information concerning the Company, including its most recent Annual Information Form, can be found at www.sedar.com.

RESPONSIBILITY FOR FINANCIAL STATEMENTS

The consolidated financial statements and all information in this Annual Report are the responsibility of management and have been approved by the Board of Directors. These consolidated financial statements have been prepared by management in conformity with accounting principles generally accepted in Canada ("Canadian GAAP") and, where appropriate, include certain estimated amounts that are based on informed judgements to ensure fair representation in all material respects. When alternative accounting methods exist, management has chosen those it considers most appropriate. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management has prepared Management's Discussion and Analysis which is based on the Company's financial results prepared in accordance with Canadian GAAP. It compares the Company's financial performance in 2005 to 2004 and should be read in conjunction with the consolidated financial statements and accompanying notes.

Management has developed and maintains a system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting, and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization. The internal accounting control process includes management's communication to employees of policies which govern ethical business conduct.

The Board of Directors is responsible for ensuring that management fulfills its responsibility for financial reporting and for final approval of the consolidated financial statements. The Board of Directors performs this responsibility primarily through its Audit Committee.

The Audit Committee is comprised solely of unrelated, independent directors and meets regularly with management and the external auditors as well as independently with the external auditors to review the consolidated financial statements, the Auditors' Report and other auditing and accounting matters. The Audit Committee reviews the Annual Report, including the consolidated financial statements, before the consolidated financial statements are submitted to the Board of Directors for approval. The Audit Committee reports its findings to the Board of Directors. The external auditors have free access to the Audit Committee without obtaining prior management approval.

With respect to the external auditors, Deloitte & Touche LLP, the Audit Committee approves the terms of engagement and reviews the annual audit plan, the Auditors' Report and results of the audit. It also recommends to the Board of Directors the external audit firm to be appointed by the shareholders.

The independent external auditors, Deloitte & Touche LLP, have been appointed by the shareholders to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's financial position, results of operations and cash flows in accordance with Canadian GAAP. The report of Deloitte & Touche LLP on page 22 outlines the scope of their examination and their opinion on the consolidated financial statements.

ROY G. DYCE
PRESIDENT AND
CHIEF EXECUTIVE OFFICER
February 16, 2006

ELIZABETH A. FLETCHER
CHIEF FINANCIAL OFFICER

AUDITORS' REPORT

TO THE SHAREHOLDERS OF PACIFIC NORTHERN GAS LTD.

We have audited the consolidated balance sheets of **Pacific Northern Gas Ltd.** as at December 31, 2005 and 2004 and the consolidated statements of income, retained earnings and cash flows for each of the years in the three year period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and 2004 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2005 in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

CHARTERED ACCOUNTANTS
VANCOUVER, CANADA,
February 16, 2006

CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31	2005	2004	2003
($ in thousands, except for per share data)			
Operating revenues (notes 3)	159,950	137,755	133,727
Cost of sales	111,287	88,954	84,417
	48,663	48,801	49,310
Operating and maintenance	10,756	12,093	12,387
Administrative and general	6,410	6,623	6,084
Amortization of deferred charges	755	763	503
Municipal and other taxes	4,120	3,941	3,982
Depreciation	8,011	7,877	7,873
	30,052	31,297	30,829
	18,611	17,504	18,481
Investment and other income	27	48	56
	18,638	17,552	18,537
Income deductions			
Interest on long term debt	7,083	7,564	7,536
Other	481	460	573
	7,564	8,024	8,109
Income before income taxes	11,074	9,528	10,428
Income taxes (note 5) – current	2,775	2,646	3,870
– deferred	1,639	1,474	890
	4,414	4,120	4,760
Net income for the year	6,660	5,408	5,668
For common shares			
Net income for the year	6,660	5,408	5,668
Dividends on preferred shares	337	337	337
Net income applicable to common shares, basic and diluted	6,323	5,071	5,331
Earnings per common share (note 1)			
Basic	$1.75	$1.41	$1.49
Diluted	$1.72	$1.38	$1.46
Weighted average number of common shares outstanding			
Basic	3,619,579	3,596,706	3,583,121
Effect of dilutive stock options	56,592	70,389	58,119
Diluted	3,676,171	3,667,095	3,641,240

See accompanying notes

CONSOLIDATED BALANCE SHEETS

As at December 31	2005	2004
($ in thousands)		
ASSETS (notes 7 and 8)		
Current assets		
Accounts receivable (note 3)	28,831	23,304
Income taxes recoverable (note 5)	375	362
Inventories of supplies and natural gas	2,688	1,725
Prepaid expenses	1,800	215
	33,694	25,606
Plant, property and equipment (note 4)	171,351	176,780
Deferred charges (note 2)		
Debt costs	615	754
Rate stabilization adjustment mechanism	2,311	1,788
Pipeline rehabilitation costs	1,011	1,128
Deactivated assets	5,050	–
Other	1,178	1,601
	10,165	5,271
	215,210	207,657
LIABILITIES Commitments, guarantees and contingency (notes 14, and 15)		
Current liabilities		
Bank indebtedness (note 7)	10,159	6,046
Accounts payable and accrued liabilities	21,121	16,046
Gas purchase variance payable (note 2)	881	2,232
Other taxes payable	3,263	2,726
Long term debt due within one year (note 8)	4,880	4,380
	40,304	31,430
Non-current liabilities (note 6)	224	407
Long term debt (note 8)	76,560	81,440
Deferred income taxes (note 5)	15,430	15,430
	92,214	97,277
	132,518	128,707
SHAREHOLDERS' EQUITY		
Preferred shares (note 9)	5,000	5,000
Common shares (notes 10 and 11)	9,065	9,009
Contributed surplus (notes 10 and 11)	2,828	2,567
Retained earnings	65,799	62,374
Common shareholders' equity	77,692	73,950
	82,692	78,950
	215,210	207,657

See accompanying notes

On behalf of the Board:

ROY G. DYCE
DIRECTOR

ROBERT F. CHASE
DIRECTOR

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31 ($ in thousands)	2005	2004	2003
OPERATING ACTIVITIES			
Net income for the year	6,660	5,408	5,668
Add (deduct) items not involving cash:			
Deferred income taxes	1,639	1,474	890
Depreciation and amortization (note 16)	8,905	8,800	8,452
Stock option expense (note 11)	132	93	56
Other	(1,702)	(1,116)	(913)
Operating cash flow	15,634	14,659	14,153
Non-cash working capital changes (note 16)	(3,827)	1,708	(1,941)
Net cash provided by operating activities	11,807	16,367	12,212
INVESTING ACTIVITIES			
Additions to plant, property and equipment (note 4)	(6,753)	(11,276)	(5,406)
Increase in deferred charges (note 2)	(1,737)	(1,096)	(2,519)
Net cash used by investing activities	(8,490)	(12,372)	(7,925)
FINANCING ACTIVITIES			
Increase in bank indebtedness	4,113	3,146	2,900
Repayment of long term debt	(4,380)	(4,380)	(3,880)
Issue of common shares (note 10)	185	143	36
Dividends paid	(3,235)	(3,217)	(13,057)
Net cash used by financing activities	(3,317)	(4,308)	(14,001)
Decrease in cash and cash equivalents during the year	–	(313)	(9,714)
Cash and cash equivalents, beginning of year	–	313	10,027
Cash and cash equivalents, end of year	–	–	313

Supplemental cash flow information (note 16)

See accompanying notes

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Years ended December 31 ($ in thousands)	2005	2004	2003
Balance, beginning of year	62,374	60,183	57,719
Net income for the year	6,660	5,408	5,668
	69,034	65,591	63,387
Preferred share dividends	337	337	337
Common share dividends	2,898	2,880	2,867
	3,235	3,217	3,204
Balance, end of year	65,799	62,374	60,183

See accompanying notes

1 SUMMARY OF ACCOUNTING POLICIES

Regulation and Related Disclosure

Pacific Northern Gas Ltd. and its wholly owned subsidiary, Pacific Northern Gas (N.E.) Ltd., are regulated utilities engaged in the transportation and distribution of natural gas. Their accounting records and practices conform to the requirements of the British Columbia Utilities Commission (the "Commission"). The Commission exercises statutory authority over matters such as rates, including rate of return on equity and capital structure, construction and operation of facilities, accounting practices, tolls, charges and contractual agreements with customers. In order to comply with orders issued by the Commission, the timing of recognition of certain revenues and expenses may differ from that which would otherwise be required under Canadian generally accepted accounting principles for non rate-regulated entities.

Effective December 31, 2005, the Company adopted the new Accounting Guideline AcG-19, *Disclosure by Entities subject to Rate Regulation*, which applies to years ending on or after December 31, 2005. AcG-19 provides guidance about certain aspects of the disclosure and presentation of information of entities providing services or products for which customer rates are established or approved by a regulator. The objective is to ensure that financial statement users are better informed about the existence, nature and effects of all forms of rate regulation. If rate regulation has an impact on the accounting treatment of a transaction, the entity should make mention of it and provide additional information about the impact on its financial statements.

The financial effects of rate regulation relate principally to balances and the accounting policies noted below. Disclosure of the impact of rate regulation on these balances and policies are included in the related notes as referenced:

~ Deferred charges and liabilities (note 2)
~ Property, plant and equipment and related depreciation rates (note 4)
~ Income taxes (note 5)
~ Employee future benefit plans for post-retirement non-pension benefits (note 6)
~ Hedges, derivatives and other financial instruments (note 14)

Consolidation

The consolidated financial statements include the accounts of Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. (collectively the "Company") and are prepared in accordance with Canadian generally accepted accounting principles.

Use of Estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities.

Significant balances impacted by estimates include operating revenues which include estimates of customer usage from the last meter reading date to the end of the reporting period, and accounts receivable which are recorded net of an estimated allowance for doubtful accounts. Actual results could differ from these estimates.

Revenue Recognition

The Company's operations are subject to rate-regulation and accordingly there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner that is consistent with the underlying rate-setting mechanism as mandated by the Commission. This may result in the recognition of regulatory assets and liabilities.

Operating revenues include natural gas sales that are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading date to the end of the year. Operating revenues also include transportation services revenues that are recorded as service is provided, as well as sales of gas surplus to the needs of the Company's sales customers ("off system sales") that are recognized when the gas is delivered.

Cash and Cash Equivalents

Cash and cash equivalents are held for the purpose of meeting short-term cash commitments and include bank balances and term deposits with maturities of less than 90 days.

Inventories of Supplies and Natural Gas

Inventories of supplies and line-pack natural gas are valued at the lower of cost determined on a first-in, first-out basis and net realizable value. Inventories of natural gas in storage are valued at the lower of average cost and net realizable value.

Included in, or deducted from, inventories of natural gas are amounts for natural gas to be received from, or returned to transportation service customers. This amount represents the difference between natural gas received on behalf of the transportation service customers and natural gas delivered to them.

Deferred Charges and Liabilities

The Company defers certain charges which the Commission or contractual arrangement require or permit to be recovered through future rates. Deferred charges and credits are amortized over various periods as approved by the Commission, depending on the nature of the charges or credits (see note 2).

Deferred charges include long-term debt issue costs which are amortized over the term of the related debt which approximates the effective interest method.

Plant, Property and Equipment

Plant, property and equipment are recorded at cost less contributions in aid of construction. Cost includes an allowance for funds used during construction calculated at the Company's cost of capital. As directed by the Commission, the cost of depreciable assets retired, together with removal costs, less salvage is charged to accumulated depreciation. Gains or losses on disposal are not taken into income unless the disposal is outside the normal course of business or involves a major item of plant.

Depreciation is provided on a straight-line basis for plant in service at the commencement of each fiscal year at rates approved by the Commission (see note 4).

Asset Retirement Obligations

The fair value of asset retirement obligations associated with the retirement of long-lived assets is recognized in the period when it can be reasonably determined. The fair value, which approximates the cost a third party would charge in performing the tasks necessary to retire such assets, is recognized at the present value of expected future cash flows and is added to the carrying value of the associated asset and depreciated over the asset's useful life. The liability is accreted over time through periodic charges to earnings and is reduced by actual costs of decommissioning and reclamation.

The Company's natural gas transmission and distribution long-lived assets are comprised principally of mains, service lines, compressors, and measuring and regulating equipment. No amount has been recorded for asset retirement obligations relating to the Company's assets as it is not possible to make a reasonable estimate of the fair value of the liability due to the indeterminate timing and scope of the asset retirements. Management expects all retirement costs associated with the regulated assets will be recovered through tolls in future periods and therefore any liability recorded would be offset by an asset.

Income Taxes

The Company provides for income taxes using the income taxes currently payable method as directed by the Commission, except as described below. Under the income taxes currently payable method, no provisions are made for income taxes deferred as a result of differences in timing between the treatment for income tax and accounting purposes of various income and expenditure items (see note 5).

1 SUMMARY OF ACCOUNTING POLICIES (CONT'D)

The Commission has directed that the deferral method of accounting for income taxes be followed for certain transactions within the Company. Under the deferral method of accounting for income taxes, reported earnings are charged with the income taxes related to those earnings. Differences between these taxes and taxes currently payable, arising mainly from differences in the timing of expense deductions, are recorded as deferred income taxes.

Employee Future Benefit Plans

The Company accrues its pension obligations under employee benefit plans and the related costs, net of plan assets. The actuarial determination of the accrued benefit obligation uses the projected benefit method prorated on service (which incorporates management's best estimate of future salary levels, other cost escalations, retirement ages of employees, and other actuarial factors).

For the purpose of calculating the expected return on plan assets, those assets are valued at a market-related value. The market-related value of assets is determined as the average of the fair value of plan assets and four projected values. The projected values are determined by projecting the fair value as at a particular time (1 year, 2 years, 3 years and 4 years prior to the measurement date) to the measurement date using actual non-investment cash flows and an assumed investment return equal to the average market-related value return on three month T-Bills plus 2.5%.

Actuarial gains (losses) arise from the difference between the actual long term rate of return on plan assets for a period and the expected long term rate of return on plan assets for the period, or from changes in actuarial assumptions used to determine the accrued benefit obligation. The excess of the net unamortized cumulative actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of the plan asset at the beginning of the year is amortized over the average remaining service period of the active employees. Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment.

The average remaining service period of the active employees covered by the pension plan is 14 years.

For the defined contribution plan maintained by the Company, contributions payable by the Company are expensed as pension costs.

Other retirement benefit plans are non-contributory health care and life insurance plans. Prior to 2004, the Company used the pay-as-you-go method of accounting for non-pension benefits as directed by the Commission. Beginning in 2004, both the current service cost and the benefits paid to retirees are expensed and recovered in customer rates. The accrued benefit obligation is included on the balance sheet in non-current liabilities.

Financial Instruments

Derivative and other financial instruments are utilized in connection with management of gas supply and interest rates. The Company enters into forward, future, swap, fixed price and option contracts to manage the impact of market fluctuations on assets, liabilities, or other contractual commitments. The Company defers the impact of changes in the market value of these contracts until such time as the associated transaction is completed.

Credit risk is the risk of loss from non-performance of suppliers, customers or financial counterparties to a contract. The Company maintains credit policies which management believes significantly minimize overall credit risk. These policies include a review of a counterparty's financial condition, measurement of credit exposure and monitoring of concentration of exposure to any one customer or counterparty.

Earnings Per Common Share

Basic earnings per common share are calculated using the weighted average number of common shares outstanding during the year. Diluted earnings per share are calculated using the treasury stock method whereby the weighted average number of common shares outstanding during the year is adjusted to reflect the potential exercise of dilutive share purchase options.

There are 96,000 (2004 - 84,200; 2003 - 71,500) stock options outstanding during the year that could potentially dilute basic earnings per share in the future that were not included in the computation of diluted earnings per share because the options' exercise price were greater than the average market price of the common shares.

Stock Based Compensation

Stock options granted after January 1, 2003 are accounted for under the fair value method. Under this method, compensation expense is measured at fair value at the grant date using the Black-Scholes option pricing model and recognized over the vesting period with a corresponding credit to contributed surplus. Stock options granted prior to January 1, 2003 continue to be accounted for as capital transactions when the options are exercised, which does not give rise to compensation expense.

New Accounting Standards

New accounting standards will be in effect for fiscal years beginning on or after October 31, 2006 for hedge accounting, recognition and measurement of financial instruments and disclosure of comprehensive income. The Company is currently investigating the impact of these new standards.

Comparative Figures

Certain of the prior year figures have been reclassified to conform to the current year's presentation.

2 FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

General Information on Rate Regulation and its Economic Effects

The Company and its subsidiary are regulated by the Commission. Customer rates are set under a cost of service methodology that allows revenues to be set to recover the Company's forecast costs and to earn a rate of return on common equity. Applications for changes to rates are made annually and are submitted to the Commission for their review and approval.

Forecast costs include gas commodity and transportation, operation and maintenance, depreciation, property taxes, interest and income taxes. The rate base is the average level of investment in all recoverable assets used in gas transmission and distribution, and an allowance for working capital. Under cost of service regulation, it is the responsibility of the Company to demonstrate to the Commission the prudence of the costs it has incurred. For 2005, the Company's average approved rate of return on the rate base was 8.60 percent after tax, and the average approved rate of return on common equity was 9.63 percent after tax, based on weighting using the respective rate bases of the Company and its subsidiary. The Company's deemed common equity was greater than 36 percent but with no specific figure identified by agreement between the Company and its customers under a negotiated settlement of the 2005 rates. The deemed common equity of its subsidiary was 36 percent in 2005.

Regulatory Assets and Liabilities

Certain regulatory assets represent future revenues associated with certain costs, incurred in the current period or in prior periods that are expected to be recovered from customers in future periods through the rate-setting process. In the absence of rate regulated accounting, generally accepted accounting principles would not permit deferral of regulatory assets and therefore the earnings impact would be recorded in the period of recovery. Long-term regulatory assets are recorded in deferred charges in the consolidated balance sheets.

Regulatory liabilities represent future reductions or limitations of increase in revenues associated with amounts that are expected to be refunded to customers as a result of the rate-setting process. The treatment under generally accepted accounting principles of regulatory liabilities and the resulting earnings impact is the same as that under rate regulated accounting because the liabilities represent contractual obligations. Regulatory liabilities are shown on the consolidated balance sheets in current liabilities.

2 FINANCIAL STATEMENT EFFECTS OF RATE REGULATION (CONT'D)

Regulatory Risk and Uncertainties Affecting Recovery or Settlement

The regulatory assets and liabilities recorded in the financial statements are based upon an expectation of the future actions of the regulator. To the extent that the regulator's future actions are different from the Company's expectations, the timing and amount of recovery or settlement of amounts recorded on the consolidated balance sheets could be significantly different from the timing and amounts that are eventually recovered or settled.

Financial Statement Effects

In order to recognize the economic effects of the actions or expected actions of the regulator, the timing of recognition of certain revenues and expenses may differ from that otherwise expected under generally accepted accounting principles for non rate-regulated entities.

Accounting for rate-regulated entities has resulted in recording the following regulatory assets and liabilities:

Deferred Charges and Liabilities

Description	Period of Recovery	Income Statement Effect 2005	Carrying Amount 2005	Carrying Amount 2004
($ in thousands)				
Deferrals included in rate base				
Rate Stabilization Adjustment Mechanism[1]	Over three-years, based on forecast customer deliveries	876	2,311	1,788
Pipeline rehabilitation costs[2]				
Extraordinary pipeline losses	Straight-line over 10 years, between 2006 and 2014	–	62	70
Pipeline breaks	Straight-line over 10 years, between 2006 and 2014	21	739	809
Stress Corrosion Cracking	Straight-line over 10 years, between 2006 and 2015	42	210	249
Total pipeline rehabilitation costs		63	1,011	1,128
Other rate base deferrals				
Preliminary surveys and investigations[3]	Depreciated over the life of the related asset commencing when placed into service	350	355	13
Property taxes[4]	1 year, 2006	80	80	225
Industrial customer deliveries[5]	Straight-line over 3 years, 2006 to 2008	311	696	602
Commission hearing costs[6]	1 year, 2006	485	409	24
Other	Straight-line over 3 to 10 years	143	252	268
Total other rate base deferrals		1,369	1,792	1,132
Deferrals excluded from rate base				
Deactivated assets[7]	Straight-line over 10 years, to 2015	5,050	5,050	–
Other deferrals excluded from rate base				
Depreciation adjustment liability for prior year retirements[8]	1 year, 2006	(637)	(637)	–
Propane air plant[9]	Straight-line over 10 years, to 2014	(318)	412	792
Interest[10]	Straight-line over 2 years, 2006 to 2007	(186)	(315)	(248)
Other		(59)	(74)	(75)
Other deferrals excluded from rate base		(1,200)	(614)	469
Total deferred charges		6,158	9,550	4,517
Regulatory liabilities excluded from rate base				
Gas purchase variance payable[11]	Based on forecast deliveries over 3 years, to 2008	(283)	(881)	(2,232)

The income statement effect noted in the above table indicates the effect, either increase or (decrease), on 2005 after tax net income as a result of the treatment under rate regulated accounting. The carrying amount for 2005 and 2004 is the cost amount of the deferral less income taxes and accumulated amortization, at December 31, 2005 and December 31, 2004, respectively.

1. Rate Stabilization Adjustment Mechanism

The Company is authorized by the Commission to maintain a rate stabilization adjustment mechanism ("RSAM") deferral account to mitigate the effect on its earnings of volatility in deliveries to certain customers caused principally by weather and natural gas cost volatility. The RSAM deferral account accumulates the margin impact of variations in the actual versus forecast use for residential and small commercial customers. Balances in the RSAM deferral account are recovered in customer rates over a three year period based on forecast deliveries. During 2005, approximately $353,000 of the December 31, 2004 RSAM balance was recovered in customer rates (2004 - $282,000).

2. Pipeline rehabilitation costs

The cost of carrying out temporary repairs of pipeline breaks as well as the related undepreciated net book value of pipeline assets destroyed as a result of pipeline breaks is recorded in deferral accounts for future recovery from customers. In addition, the cost of investigative work and repair of pipeline assets at risk due to stress corrosion, cracking or other material defects is deferred for future recovery in customer rates.

3. Preliminary surveys and investigations

The Company defers costs associated with the development of new projects that would be beneficial to its customers. In 2005 the Company commenced preliminary study and investigation of a project to loop its main line transmission system from Kitimat to Summit Lake (the "KSL Project"). The KSL Project would be required to provide gas transportation services for liquefied natural gas to be imported and regasified at the proposed Kitimat LNG Inc. terminal to be located on the Douglas Channel approximately 15 kilometers southwest of Kitimat. In 2005 the Company incurred costs of $0.9 million associated with the KSL Project. Kitimat LNG Inc. is obligated to fund $0.4 million of this amount under an agreement with the Company. The Company has a contingent obligation to refund all or part of the funding provided by Kitimat LNG Inc. as described in note 15 below. On commencement of construction of the Kitimat LNG Inc. terminal, the deferred costs will be transferred to construction work in progress. In the event the terminal is not constructed, the Company will seek recovery of the deferred costs in future customer rates. The ultimate recovery of this deferred charge is subject to a future decision of the Commission.

4. Property taxes

As directed by the Commission, a deferral account is used to recover the difference between actual and forecast property taxes, to be recovered from (or refunded to) customers in rates over the following year.

5. Industrial customer deliveries

As directed by the Commission, a deferral account is used to recover the lost margin from certain large industrial customers whose deliveries varied from expectations. The amount deferred during the year ended December 31, 2003 is being amortized over three years, commencing in 2004. The credit amount deferred in 2004 was amortized entirely in 2005. Amortization of $230,000 has been included in net income during 2005 related to these deferred costs. The Company has applied to the Commission for a three-year amortization period for the 2005 deferral, commencing in 2006.

6. Commission hearing costs

The Company's annual revenue requirements application contains a forecast of the costs that the Company will incur relating to the Commission's review of the application. The total actual costs are usually not known by the Company until a few months after the conclusion of the Commission's review process and the implementation of new customer rates. Therefore, customer rates reflect forecast costs of the review process and the Company records in a deferral account the difference between forecast and actual costs for future recovery from or refund to customers.

7. Deactivated assets

In its 2006 Revenue Requirements Application, the Company identified plant, property and equipment assets which would not be required on an ongoing basis to provide service to its customers, having regard to the closure of the Methanex Corporation plant in late 2005 (see note 3). The Company has requested that compressor facilities, pipeline loops and various other fixed assets with a net book value of $5.05 million be removed from rate base and transferred to a non-rate base, interest bearing deferral account effective December 31, 2005. The Company has applied for the deferral account to be amortized on a straight-line basis over ten years commencing in 2006. The ultimate recovery of this deferred charge is subject to a future decision of the Commission.

2 FINANCIAL STATEMENT EFFECTS OF RATE REGULATION (CONT'D)

8. Depreciation adjustment for prior year retirements

As a result of detailed analysis of property, plant and equipment cost and retirement records conducted in 2005, various assets were identified as retired or disposed in prior years, between 1988 and 2001; however, no retirement was recorded at the time. Approximately $637,000 of accumulated depreciation expense was identified which should not have been recorded in the years 1989 to 2005. The Company has reversed this accumulated deprecation, and transferred the balance to a deferred credit, for refund to customers in 2006. The ultimate realization of this deferred credit is subject to a future decision of the Commission.

9. Propane air plant

In 2004, the net book value of a propane air plant which is no longer in service with an undepreciated value of $966,000 was removed from fixed assets and transferred to a deferral account for future recovery from customers over a period of twenty years commencing in 2005. As part of the negotiated settlement process for determining 2005 customer rates, the Company agreed to expense $165,000 of the relocation expenses previously deferred in 2004. This amount has been included in other income deductions in the 2005 consolidated statement of income. In addition, $242,000 of the amounts deferred in 2004 were returned to rate base and reclassified to plant property and equipment, effective January 1, 2005.

10. Interest

As directed by the Commission, the Company has an interest deferral mechanism that mitigates exposure to fluctuations in floating interest rates on both short term and long term debt instruments.

11. Gas purchase variance payable

Gas purchase variance payable amounts arise due to unanticipated commodity cost and demand fluctuations between actual natural gas costs and forecast natural gas costs as recovered in rates. As directed by the Commission, gas purchase variance payable amounts are being refunded to customers on a straight-line basis over three years, based on forecast deliveries. The amount of such credits included in cost of sales in 2005 was $2,466,000 before income taxes (2004 - $2,319,000; 2003 - $1,363,000).

Other Items Affected by Rate Regulation

Future income taxes

The Company recovers tax expense based on the taxes payable method, as prescribed by the Commission, for ratemaking purposes. Under the income taxes currently payable method, no provisions are made for future or deferred income taxes as a result of differences in timing between the treatment for income tax and accounting purposes of the various income and expenditure items. Therefore, rates do not include the recovery of future income taxes related to temporary differences. Consequently, the Company does not record future income taxes for its regulated activities as the Company expects that all future income taxes will be recovered in rates when they become payable. Generally accepted accounting principles require the recognition of future income tax liabilities and future income tax assets in the absence of rate regulation.

Deferred income tax expenses shown on the consolidated statements of income arise from temporary differences related to the regulatory deferral accounts identified above. The regulatory deferral accounts are recorded on the balance sheet at December 31, 2005 net of deferred income tax liabilities of $2.0 million. In the absence of rate regulated accounting, regulatory deferrals would not be recorded nor would the associated deferred or future income tax liabilities. However, future income taxes associated with certain assets, primarily property, plant and equipment, would be recorded, in the absence of rate regulated accounting, resulting in the recognition of $20.2 million (2004 - $21.3 million) in future income tax liabilities. As a result of these impacts, earnings would increase by $1.1 million in the year ended December 31, 2005.

From July 1, 1978 until its suspension on November 1, 1986, the deferral method was followed by the Company. Had the liability method of accounting for income taxes been followed continuously since the inception of the Company, the future income tax liabilities and future income tax expense (recovery) would be:

($ in thousands)	2005	2004
Deferred income tax liabilities, as reported	15,430	15,430
Adjustment to reflect liability method	(4,783)	(4,783)
Unrecorded future income tax liabilities beginning of year	10,633	10,811
Unrecorded future income tax recovery	(1,098)	(178)
Future income tax liability	20,182	21,280

Allowance for funds used during construction (AFUDC) and other capitalized costs

AFUDC is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and a cost of equity component, as approved by the Commission. In the absence of rate regulation, generally accepted accounting principles would permit the capitalization of only the interest component. Therefore, the recording of the equity component as a capitalized asset and the corresponding earnings recognized during the construction phase would not be recognized nor would the subsequent depreciation of the capitalized equity component. It is not possible to make a reasonable estimate of the carrying value of the equity component of AFUDC included in property, plant and equipment. In 2005, the Company capitalized AFUDC amounting to $258,000 (2004 - $47,000; 2003 - $66,000).

When a fixed asset is retired or otherwise disposed of, the Company does not reflect a gain or loss in income. Entities not subject to rate regulation write off the net book value of the retired asset and include any resulting gain or loss in current operating results. Since the Company does not calculate depreciation expense for individual assets, it cannot identify or quantify gains or losses on the retirement of a fixed asset in any given year.

Interest capitalization

The Company is permitted to earn a short term interest return on deferrals excluded from rate base. For the years 2003 through 2005, interest was capitalized at 6 percent on all regulatory deferrals excluded from rate base. In the absence of rate regulation, generally accepted accounting principles would not permit the capitalization of interest on deferrals. Therefore, the recording of the interest component as a deferred asset or liability and the corresponding earnings adjustment would not be recognized nor would the subsequent amortization of the capitalized interest component. In 2005, this resulted in a charge to income of $175,000 (2004 - charge of $135,000; 2003 - credit of $38,000).

Overhead capitalization

With the approval of the Commission, the Company capitalizes a percentage of certain operating, administrative and general costs into the rate base on an ongoing basis. Such treatment is accorded in recognition of the significance of plant, property and equipment constructed by the Company. The Company is authorized to charge depreciation and earn a rate of return on the net book value of such capitalized costs in future years. In the absence of rate regulated accounting, such overhead costs would be charged to the consolidated statement of earnings in the period in which they occurred. In 2005, the Company capitalized $1.42 million of overhead costs to plant, property and equipment (2004 - $1.53 million; 2003 - $1.27 million).

Non-Pension post retirement benefits

The Company provides for post-retirement benefits other than pensions. The cost of providing these benefits are expensed when paid. In addition, since 2004 the Company has expensed the current service cost relating to benefits earned by employees in the current year. Under generally accepted accounting principles, the Company would also expense the annual interest cost and amortize any actuarial gains and losses into income. Had these costs been accrued, earnings in 2005 would have decreased by $221,000 (2004 - $315,000; 2003 - $552,000) (see note 6).

3 MAJOR CUSTOMERS

The proportion of energy deliveries and operating revenues attributable to large industrial customers is as follows:

	2005		2004		2003	
	Energy	Operating revenues	Energy	Operating revenues	Energy	Operating revenues
(Percent)						
Methanex Corporation	62	7	67	9	65	9
West Fraser Mills Ltd., Alcan Inc. and British Columbia Hydro and Power Authority	9	5	8	6	8	8

At December 31, 2005, 7% (2004 - 9%; 2003 - 8%) of accounts receivable was attributable to these four customers. The Company is exposed to credit risk in the event of non-performance by customers, but does not anticipate such non-performance. The Company monitors the credit risk and credit rating of industrial customers on a regular basis. The maximum credit risk is the fair value of the accounts receivable.

On August 30, 2005, Methanex Corporation gave notice of termination of its Firm and Interruptible Gas Transportation Service Agreement with the Company. Under the terms of the agreement, Methanex is required to make a termination payment to the Company of approximately $23.3 million on February 28, 2006, the effective date of the termination. Under the terms of a negotiated settlement with registered intervenors and approved by the Commission on November 17, 2005, the termination payment will be recorded as an interest bearing credit deferral, and will be amortized into income over the period from March 1, 2006 to October 31, 2009.

4 PLANT, PROPERTY AND EQUIPMENT

As at December 31, 2005	Average Depreciation Rate	Cost	Accumulated Depreciation	Net Book Value
($ in thousands)	Percent			
Transmission plant	2.8	172,212	68,618	103,594
Distribution plant	2.6	86,200	30,784	55,416
General plant	4.3	21,146	9,394	11,752
Processing plant	4.9	745	458	287
Construction in progress	–	302	–	302
	2.8	280,605	109,254	171,351

As at December 31, 2004	Average Depreciation Rate	Cost	Accumulated Depreciation	Net Book Value
($ in thousands)	Percent			
Transmission plant	2.7	180,290	74,142	106,148
Distribution plant	2.6	84,330	28,916	55,414
General plant	5.4	21,309	10,928	10,381
Processing plant	4.9	633	375	258
Construction in progress	–	4,579	–	4,579
	2.9	291,141	114,361	176,780

During the year, the Company received contributions in aid of construction of $278,000 (2004 -$257,000; 2003 - $176,000), which have been recorded as a reduction of distribution plant.

The following table provides information on the changes in the balance of plant, property and equipment cost:

($ in thousands)	2005	2004
Cost, beginning of year	291,141	281,789
Capital expenditures, net of contributions in aid of construction	6,847	11,340
Depreciation capitalized	191	212
Plant retirements	(2,235)	(398)
Deactivated assets (note 2)	(15,581)	–
Cost transferred from (to) deferred charges (note 2)	242	(1,802)
Cost, end of year	280,605	291,141

The following table provides information on the changes in the balance of accumulated depreciation:

($ in thousands)	2005	2004
Accumulated depreciation, beginning of year	114,361	107,441
Depreciation expense	8,011	7,877
Depreciation capitalized	191	212
Plant retirements	(2,235)	(398)
Salvage on plant retirements	94	65
Deactivated assets (note 2)	(10,531)	–
Accumulated depreciation transferred from (to) deferred charges (note 2)	–	(836)
Depreciation adjustments for prior year retirements (note 2)	(637)	–
Accumulated depreciation, end of year	109,254	114,361

5 INCOME TAXES

Significant components of the Company's deferred tax liabilities are as follows:

($ in thousands)	2005	2004
Deferred income tax liabilities		
Capital cost allowance claimed for income tax purposes in excess of depreciation and amortization	14,462	14,462
Other	968	968
Deferred income tax liabilities	15,430	15,430

Income tax expense varies from the amount that would be expected if current rates were applied to income before income taxes for the following reasons:

(Percent)	2005	2004	2003
Combined Canadian federal and provincial statutory income tax rates, including surtaxes	34.9	35.6	37.6
Increase (decrease) in income taxes resulting from:			
Large corporations tax	2.2	3.1	4.5
Depreciation in excess of capital cost allowance	5.4	7.0	6.6
Amortization of intangibles	2.5	3.1	1.8
Capitalized overhead deducted for tax purposes	(3.8)	(4.9)	(3.9)
Other items	(1.5)	(0.7)	(1.0)
Effective rate of income taxes	39.7	43.2	45.6

6 EMPLOYEE FUTURE BENEFIT PLANS

The Company and its subsidiary have a number of funded and unfunded defined benefit plans, as well as defined contribution plans, that provide pension, other retirement and post-employment health and life insurance benefits for most employees. Benefits earned under the defined benefit plans are principally based on years of service and average earnings.

6 EMPLOYEE FUTURE BENEFIT PLANS (CONT'D)

The measurement dates of the funded plans, as wells as the effective dates of the most recent actuarial valuations and the next required actuarial valuations for the purpose of funding the funded plans are as follows:

	2005	2004
Measurement date of the plan assets and accrued benefit obligation	September 30,2005	September 30, 2004
Effective date of the most recent actuarial valuation report for funding purposes	December 31, 2003	December 31, 2003
Effective date of the next required actuarial valuation report for funding purposes	December 31, 2006	December 31, 2006

(a) Information about the defined benefit pension plans is as follows:

($ in thousands)	2005	2004	2003
Accrued benefit obligations			
Balance, beginning of year	19,235	17,224	15,323
Current service cost	682	595	419
Employees' contributions	7	8	4
Interest cost	1,148	1,028	987
Benefits paid	(889)	(777)	(680)
Actuarial losses	2,394	1,157	1,171
Balance, as at measurement date	22,577	19,235	17,224
Plan assets			
Fair value, beginning of year	14,038	12,720	11,601
Actual return on plan assets	1,785	1,590	1,426
Employer contributions	1,165	497	369
Employees' contributions	7	8	4
Benefits paid	(889)	(777)	(680)
Fair value, as at measurement date	16,106	14,038	12,720
Funded status – plan deficit	(6,471)	(5,197)	(4,504)
Unamortized net actuarial losses	6,216	4,749	4,456
Unamortized past service costs	–	–	1
Unamortized transitional asset	(28)	(26)	(24)
Accrued benefit obligation as at measurement date	(283)	(474)	(71)
Employer contribution between measurement date and year end	237	593	109
Accrued benefit assets (liability) end of year	(46)	119	38

The following is a summary of the significant actuarial assumptions used in measuring the Company's accrued pension benefit obligations:

(Percent)	2005	2004	2003
Accrued benefit obligation as of December 31, with a measurement date of September 30:			
Discount rate	5.25	6.00	6.00
Rate of compensation increase	3.25	3.25	3.25
Benefit costs for years ended December 31, with a measurement date of September 30:			
Discount rate	6.00	6.00	6.50
Expected long-term rate of return on plan assets	7.50	7.50	7.75
Rate of compensation increase	3.25	3.25	3.25

The following table shows the allocation of the pension plan assets at the measurement dates:

(Percent)	2005	2004
Asset category:		
Cash and short-term notes	5.2	4.2
Canadian bonds	35.0	38.4
Canadian equities	32.0	33.8
Foreign equities	27.8	23.6
	100.0	100.0

The Company's pension plan expense is as follows:

($ in thousands)	2005	2004	2003
Current service cost	682	595	419
Interest cost	1,148	1,028	987
Expected return on plan assets	(1,069)	(930)	(1,116)
Amortization of past service costs	–	1	2
Amortization of net actuarial loss	211	214	40
Amortization of transitional asset	2	2	2
Net defined benefit pension plan expense	974	910	334
Defined contribution pension plan expense	58	46	49
Total pension expense	1,032	956	383

(b) Information about the non-pension post-retirement benefit obligation is as follows:

($ in thousands)	2005	2004	2003
Balance, beginning of year	4,162	4,739	4,167
Current service cost	115	180	160
Interest cost	247	284	273
Benefits paid	(199)	(192)	(101)
Actuarial loss (gain)	758	(849)	240
Balance, as at measurement date	5,083	4,162	4,739
Funded status – plan deficit	(5,083)	(4,162)	(4,739)
Unamortized net actuarial losses	4,788	3,982	4,739
Accrued benefit obligation as at measurement date	(295)	(180)	–
Employer contribution between measurement date and year end	295	–	–
Accrued benefit obligation, end of year	–	(180)	–

Effective January 1, 2004, the Company changed the method of expensing non-pension post-retirement benefits on a prospective basis (note 1). Prior to that date, only benefits paid were expensed. Beginning in 2004, both the current service cost and the benefits paid are expensed and recovered in customer rates. The accrued benefit obligation at December 31, 2004 is included on the balance sheet in non-current liabilities. Commencing in 2005, the amounts expensed in 2004 and 2005 have been funded through contributions to a retirement compensation arrangement, as directed by the Commission.

The assumed extended health care cost trend used for measurement purpose is 10.0% per annum, grading down over 5 years to 5.0% and remaining at that level thereafter. The assumed dental premium trend used for measurement purposes is 7.0% per annum for the first 10 years and 6.0% per annum thereafter.

The Company's non-pension post-retirement benefit expense is as follows:

($ in thousands)	2005	2004	2003
Current service cost	115	180	–
Benefits paid	199	192	101
Non-pension post-retirement benefit expense, as reported	314	372	101
Current service cost	–	–	160
Interest cost	247	284	273
Amortization of transitional obligation	123	123	123
Amortization of net actuarial loss	50	100	97
Less benefits paid, expensed above	(199)	(192)	(101)
Non-pension post-retirement benefit plan expense, accrual method	535	687	653

Total cash payments for employee future benefits are $1,489,000 in 2005 (2004 - $1,153,000; 2006 - $628,000), consisting of cash contributed to funded pension plans, cash payments in respect of non-pension post-retirement benefits, and cash contributed to defined contribution pension and non-pension post retirement benefit plans.

7 BANK INDEBTEDNESS

($ in thousands)	2005	2004
Bank overdraft	10,159	946
Bank demand operating line of credit	–	5,100
Bank indebtedness	10,159	6,046

The Company has lines of credit that provide for a bank operating facility and hedge line of credit totalling $35 million (2004 - $25 million). The lines of credit have a term of 18 months, expiring June 24, 2006. The amount available under the operating facility is subject to borrowing base requirements. The lines of credit are collateralized by the pledge of a $40 million debenture and a charge on certain accounts receivable and inventories. The operating facility bears interest at prime rate or bankers' acceptance rates (December 31, 2005 - 5.0%; December 31, 2004 - 4.25%) and provides funds for general corporate and working capital requirements. At December 31, 2005, the amount available under the facility was approximately $18.5 million, $10.2 million of which had been drawn.

8 LONG TERM DEBT

($ in thousands)	2005	2004
A Secured Debentures		
RoyNat Debenture due January 15, 2011, bearing interest at a floating rate (December 31, 2005 - 6.342%), payable in monthly instalments of $110,000, with a final instalment of $120,000 at maturity.	6,720	8,040
RoyNat Debenture due December 15, 2012, bearing interest at a floating rate (December 31, 2005 - 6.842%), payable in monthly instalments of $105,000, with a final instalment of $2,505,000 at maturity.	11,220	12,480
2011 Series Debenture, 10.75% due December 13, 2011, payable in annual instalments of $700,050, and $800,000 in each of years 2009 and 2010 with a final instalment of $5,000,000 at maturity.	8,700	9,400
2018 Series Debenture, 8.75% due November 15, 2018, payable in annual instalments of $600,000, commencing November 15, 1999 and $1,000,000 in each of the years 2014 to 2017, with a final instalment of $7,000,000 at maturity.	15,800	16,400
2025 Series Debenture, 9.30% due July 18, 2025, payable in annual instalments of $500,000, commencing July 18, 2004 with a final instalment of $9,500,000 at maturity.	19,000	19,500
2027 Series Debenture, 6.90% due December 2, 2027, payable in annual instalments of $500,000, commencing December 2, 2006 with a final instalment of $9,500,000 at maturity.	20,000	20,000
	81,440	85,820
B Long term debt due within one year	4,880	4,380
	76,560	81,440

A Collateral for the Secured Debentures consists of a specific first mortgage on substantially all of the Company's plant, property and equipment and gas purchases and gas sales contracts, and a first floating charge on other property, assets and undertakings.

B Payments required to meet sinking fund and retirement provisions of long term debt during the next five years and thereafter are as follows:

($ in thousands)	
2006	4,880
2007	4,880
2008	4,880
2009	4,980
2010	4,980
Thereafter	56,840
	81,440

9 PREFERRED SHARES

($ in thousands)		2005	2004
Authorized			
1,400,000	cumulative redeemable junior preferred shares with a par value of $10		
200,000	6.75% cumulative redeemable preferred shares with a par value of $25 each		
Issued			
200,000	6.75% preferred shares	5,000	5,000

The 6.75% preferred shares are redeemable at the option of the Company at $26 per share plus any accrued and unpaid dividends at the date of redemption.

10 COMMON SHARES

($ in thousands)		2005	2004
Authorized			
6,020,000	Voting common shares with a par value of $2.50 each		
Issued			
3,626,180	Common shares (2004 - 3,603,580)	9,065	9,009

During 2005, the Company issued 22,600 common shares (2004 - 19,700) for cash consideration of $185,000 (2004 - $143,000) upon the exercise of employee options. Of this amount, $129,000 (2004 - $94,000) has been credited to contributed surplus, representing the excess of the issue price over the par value of the shares.

11 STOCK OPTION PLAN

The Company has a stock option incentive plan under which share options are granted to certain of its employees. Share options are granted at an exercise price equal to the fair market value of the Company's common shares on the date of the grant.

Share options generally vest in five equal stages with the first stage vesting on the date of the grant, and the remainder in four equal annual stages commencing on the first anniversary of the date of the grant. The maximum term of options awarded is ten years.

As of December 31, 2005, there are 307,980 (2004 - 330,580) shares reserved for issuance pursuant to options that may be granted under the stock option incentive plan.

In 2005, 31,200 options were issued at an exercise price of $19.70.

Since January 1, 2003, the Company has accounted for its grants under this plan in accordance with the fair value based method of accounting for stock-based compensation (note 1). The compensation cost that has been charged against income (and credited to contributed surplus) in 2005 is $132,000 (2004 - $93,000; 2003 - $56,000).

The fair value of each option grant is estimated on the date of the grant using the Black-Scholes option pricing model with the following assumptions:

	2005	2004	2003
Dividend yield	4%	4%	4%
Expected volatility (annualized)	29%	44%	44%
Risk free interest rate	3.7%	3.0%	3.0%
Expected years of option life (average)	7.5	7.5	7.5

A summary of the changes to of the Company's stock option plan during the years ended December 31, 2005, 2004 and 2003 is as follows:

	2005		2004		2003	
	Number of shares	Weighted-average exercise price $	Number of shares	Weighted-average exercise price $	Number of shares	Weighted-average exercise price $
Outstanding at beginning of year	278,400	15.61	272,200	14.52	247,000	14.45
Granted	31,200	19.70	25,900	20.80	34,600	14.15
Exercised	(22,600)	8.20	(19,700)	7.28	(4,800)	7.52
Expired	(19,400)	20.00	–	–	(4,600)	14.13
Outstanding at end of year	267,600	16.40	278,400	15.61	272,200	14.52
Options exercisable at end of year	206,560	15.91	212,600	15.78	197,260	15.38
Weighted average remaining contractual life	5.8 years		5.9 years		6.6 years	

11 STOCK OPTION PLAN (CONT'D)

The following table summarizes information about the stock options outstanding and exercisable as at December 31, 2005:

Expiry Date	Options Outstanding	Options Exercisable	Exercise Price $
March 14, 2006	13,200	13,200	18.75
March 14, 2007	12,700	12,700	20.75
March 24, 2008	11,500	11,500	30.50
March 11, 2009	14,700	14,700	24.50
March 16, 2010	25,200	25,200	15.50
March 21, 2011	20,600	20,600	7.85
April 27, 2011	11,700	11,700	6.50
March 15, 2012	32,200	25,500	13.50
July 4, 2012	35,000	35,000	13.50
March 13, 2013	33,700	19,860	14.15
March 2, 2014	25,900	10,360	20.80
August 5, 2015	31,200	6,240	19.70
	267,600	206,560	

12 RELATED PARTY TRANSACTIONS

The Company's transactions with related parties are as follows:

	2005	2004	2003
($ in thousands)			
Westcoast Energy Inc., parent company until December 18, 2003			
Transportation services received	–	–	876
Materials purchases and services received	–	–	463
Westcoast Energy Risk Inc., a company related through common control until December 18, 2003			
Services received	–	–	2,253
Duke Energy Marketing LP, an entity related through common control from March 14, 2002 to December 18, 2003			
Natural gas purchases	–	–	19,385
Engage Energy Canada, L.P., an entity related through common control until December 18, 2003			
Natural gas purchases and services received	–	–	197
Natural gas sales	–	–	23,121

The transactions listed above were in the normal course of operations and were recorded at amounts established and agreed between the related parties, which approximate fair market value.

On December 18, 2003, all of the common shares of the Company held by Westcoast Energy Inc. were acquired by Tricor Acquisition (STP) Inc. ("Tricor").

On March 11, 2005, the Company filed a prospectus for the public offering of 1,338,477 common shares of the Company owned by Tricor, at a price of $19.40 per common share, for gross proceeds of approximately $26 million. The common shares offered by Tricor represented 37 percent of the Company's outstanding common shares and 100 percent of Tricor's interest in the Company. The transaction was subsequently completed on April 12, 2005. The Company did not sell any newly issued common shares as part of this offering and did not receive any of the proceeds from the sale of the common shares by the selling shareholder.

13 FAIR VALUES OF FINANCIAL INSTRUMENTS

The fair values of debt instruments included in the consolidated balance sheets are as follows:

	Carrying value		Fair value	
	2005	2004	2005	2004
Long term debt	81,440	85,820	90,566	96,401

The fair value of the Company's long-term debt is estimated by reference to quoted market prices for similar instruments.

The fair values of other financial instruments included in the consolidated balance sheets, including accounts receivable, bank indebtedness, and accounts payable and accrued liabilities approximate their carrying values due to their short term nature.

14 NATURAL GAS CONTRACTS

The Company's tolls are set using a forecasted price for gas. However, some of the Company's gas supply contracts contain pricing mechanisms that reflect monthly variations in the price of gas, rather than fixed prices.

The Company had outstanding fixed price contracts, natural gas swap and collar contracts, and call options relating to natural gas supply as follows:

As at December 31, 2005

Financial Instrument	Notional Quantity (GJ's)	Percent of Annual Gas Purchases	Delivery Period	Price Range (per GJ)	Estimated Fair Value Receivable (Payable)
					($ in thousands)
Fixed price contracts	450 000	4.6	Jan. - Mar. 2006	$5.83 to $10.00	(167)
Natural gas swap contracts	1 193 000	12.1	Jan. - Oct. 2006	$7.85 to $10.60	1,670
Call options	1 219 500	12.3	Jan. - Mar. 2006	Caps from $10.00 to $15.00	633
Total	2 862 500	29.0			2,136

As at December 31, 2004

Financial Instrument	Notional Quantity (GJ's)	Percent of Annual Gas Purchases	Delivery Period	Price Range (per GJ)	Estimated Fair Value (Payable)
					($ in thousands)
Fixed price contracts	3 219 000	22.8	Jan. - Oct. 2005	$6.27 to $9.87	(3,855)
Natural gas price collar contracts	716 850	5.0	Jan. - Feb. 2005	$8.22 to $10.25	(1,406)
Total	3 935 850	27.8			(5,261)

The difference between the price of gas used for toll purposes and the actual cost of gas purchased is deferred and refunded to or recovered from customers as directed by the Commission.

The fair values reflect the estimated amounts that the Company would receive or pay at December 31 to terminate the call options, fixed price, swap or collar contracts, based on the estimated future net cash flows under the terms of each contract.

These estimated fair market values have no impact on earnings due to the regulated nature of the Company's operations. Based on the current regulatory process, any gains or losses arising from utility related financial instruments would be treated as part of the cost of service.

In the absence of rate regulation, the Company would have had to choose whether to adopt hedge accounting as outlined in Accounting Guideline 13, *"Hedging Relationships"*. In the event that the Company chose not to adopt hedge accounting, changes in the fair value of its hedging instruments would have been recorded in the statements of income and certain financial instruments would be recorded at their fair value in the balance sheet.

The Company's purchase commitments at December 31, 2005 under various gas supply contracts expiring through 2010 were as follows:

($ in thousands)	
2006	45,451
2007	1,093
2008	991
2009	941
2010	50
Thereafter	–

15 COMMITMENTS AND GUARANTEES

Under the terms of its gas transportation and supply agreements with certain customers, the Company has provided an indemnity for all damages, claims or actions arising from any act or accident in connection with the installation, presence, maintenance and operations of the Company's property and equipment, or in connection with the presence of gas deemed to be in the possession and control of the Company, and carries insurance to cover losses in the event of any claims under these provisions. The Company has also provided an environmental indemnity to certain secured debenture holders for any losses arising from non-compliance by the Company with applicable environmental laws.

Under the terms of its funding agreement with Kitimat LNG Inc., which covers a portion of certain costs incurred in the preliminary development of the KSL Project, the Company is required to repay all of the funding provided by Kitimat LNG Inc. after the commencement of construction of Kitimat LNG Inc.'s proposed liquefied natural gas import and regasification terminal. In the event construction does not proceed and the Company is permitted to recover any deferred KSL preliminary development costs in future customer rates, the recovery of costs will be shared on a pro rata basis with Kitimat LNG Inc. in proportion to the funding provided by each party.

16 SUPPLEMENTAL CASH FLOW INFORMATION

Depreciation and amortization:

	2005	2004	2003
($ in thousands)			
Depreciation, per income statement	8,011	7,877	7,873
Amortization of deferred charges, per income statement	755	763	503
Amortization of debt issue costs, included in long term interest expense	139	160	76
Total depreciation and amortization	8,905	8,800	8,452

Non-cash working capital changes:

	2005	2004	2003
($ in thousands)			
(Increase) decrease in:			
Accounts receivable	(5,527)	1,796	(3,864)
Income taxes recoverable	(13)	(362)	–
Inventories of supplies and natural gas	(963)	490	(850)
Prepaid expenses	(1,585)	(82)	67
Increase (decrease) in:			
Accounts payable and accrued liabilities	5,075	924	1,213
Gas purchase variance payable	(1,351)	(1,047)	601
Income and other taxes payable	537	(11)	892
Attributable to operating activities	(3,827)	1,708	(1,941)

Interest and tax payments:

	2005	2004	2003
($ in thousands)			
Income taxes paid	2,765	2,993	3,690
Interest paid	7,181	7,269	7,877

17 SEGMENTED INFORMATION

The Company operates in one industry and geographic segment, the transmission and distribution of natural gas within Canada. The consolidated financial statements have therefore not been segmented.

Years ended December 31	2005	2004	2003	2002	2001
OPERATING DATA					
DELIVERIES (TJ)					
Sales					
Residential	3 135	3 279	3 464	3 503	3 470
Commercial	2 659	2 655	2 845	2 897	2 862
Small industrial	689	778	825	1 050	904
Large industrial	506	626	620	594	642
	6 989	7 338	7 754	8 045	7 879
Transportation					
Commercial	61	60	64	69	74
Small industrial	2 887	2 958	2 764	2 755	2 688
Large industrial – Methanex	20 497	25 952	23 820	25 552	14 322
Large industrial – other	2 410	2 663	2 236	3 041	6 818
	25 855	31 633	28 884	31 418	23 902
TOTAL DELIVERIES	32 844	38 971	36 638	39 463	31 781
Customers At Year End	39,295	39,291	39,106	39,254	39,230
Degree days					
Actual	4,604	4,895	5,153	5,204	5,045
Normal	5,137	5,137	5,155	5,104	5,110
Actual as a percent of normal	90%	95%	100%	102%	99%

Degree day is a measure of coldness. It is calculated by accumulating for each day in the fiscal period the total number of degrees by which the daily mean temperature fell below 18 degrees Celsius. The figures given are the average for all service areas, weighted by deliveries.

FINANCIAL DATA ($ in thousands)					
REVENUE					
Sales					
Residential	42,354	37,627	38,815	30,204	39,239
Commercial	31,546	26,488	28,196	22,213	29,644
Small industrial	5,599	5,746	6,840	7,151	7,772
Large industrial	5,370	5,032	5,026	3,292	4,723
	84,869	74,893	78,877	62,860	81,377
Transportation					
Commercial	217	197	182	182	183
Small industrial	3,188	2,839	2,705	2,328	2,767
Large industrial – Methanex	12,182	12,191	12,344	20,589	19,919
Large industrial – other	2,824	3,175	5,688	3,670	8,729
	18,411	18,402	20,919	26,769	31,598
Off-system sales	56,159	43,949	33,403	18,763	24,736
Other	511	511	528	671	883
TOTAL REVENUES	159,950	137,755	133,727	109,063	138,595
EXPENSES					
Cost of sales	111,287	88,954	84,417	56,820	83,344
Operating	17,166	18,716	18,471	19,164	20,219
Interest	7,537	7,976	8,053	7,642	8,797
Municipal and other taxes	4,120	3,941	3,982	4,259	3,970
Depreciation and amortization	8,766	8,640	8,376	9,653	10,581
Income taxes	4,414	4,120	4,760	6,935	5,969
	153,290	132,347	128,059	104,473	132,880
NET INCOME	6,660	5,408	5,668	4,590	5,715
Net income applicable to common shares	6,323	5,071	5,331	4,253	5,377

FIVE YEAR REVIEW

Years ended December 31	2005	2004	2003	2002	2001
($ in thousands, except for per share data)					
CASH FLOW DATA					
Operating cash flow	15,634	14,659	14,153	14,570	15,843
Additions to plant, property and equipment	6,753	11,276	5,406	5,965	3,761
Increase (decrease) in deferred charges	1,737	1,096	2,519	372	(1,345)
Issue of long term debt	–	–	–	15,037	12,031
Repayment of long term debt	(4,380)	(4,380)	(3,880)	(2,623)	(15,326)
Dividends paid on common shares	2,898	2,880	12,719	–	–
CAPITALIZATION					
Non-current liabilities	224	407	224	–	–
Long term debt	76,560	81,440	85,820	90,200	79,539
Deferred income taxes	15,430	15,430	15,430	15,453	15,200
Preferred shares	5,000	5,000	5,000	5,000	5,000
Common equity	77,692	73,950	71,522	68,966	74,345
	174,906	176,227	177,996	179,619	174,084
UTILITY PLANT					
In service (net)	171,049	172,201	173,699	176,711	178,741
Construction in progress	302	4,579	649	603	560
	171,351	176,780	174,348	177,314	179,301
COMMON SHARE TRADING (TSX)					
High	24.00	22.00	19.50	18.00	11.00
Low	17.37	17.28	14.00	9.35	6.50
Close	19.55	20.93	19.46	17.75	9.60
Volume (in shares)	2,150,589	929,506	709,592	809,778	1,142,742
PER COMMON SHARE DATA					
Earnings applicable to common shareholders	1.75	1.41	1.49	1.20	1.52
Dividends declared on common shares	0.80	0.80	0.80	$2.75	0.00
FINANCIAL RATIOS					
Return on average shareholders' equity(1)	8.2%	6.9%	7.5%	5.6%	7.4%
Return on average capital employed(2)	6.2%	5.7%	5.8%	5.0%	5.4%
Earnings coverage of interest(3)	2.5	2.2	2.3	2.5	2.3
Dividend payout ratio	45.7%	56.7%	53.7%	229.2%	0.0%

(1) Net income applicable to common shareholders divided by average common equity (weighted quarterly during the year)

(2) Sum of net income and after-tax interest expense divided by average capital employed (weighted quarterly during the year). Average capital employed is equal to the sum of shareholders' equity, deferred income taxes, deferred credits, and total debt.

(3) Earnings before interest and taxes divided by total interest.

ALLOWED RETURN ON COMMON EQUITY:					
Western system	9.68%	9.80%	10.17%	9.88%	10.00%
Fort St. John / Dawson Creek division	9.43%	9.55%	9.82%	9.63%	9.75%
Tumbler Ridge division	9.68%	9.80%	10.07%	9.88%	10.00%

DIRECTORS — DIRECTOR SINCE

ROBERT F. CHASE [1,2,4]
PRESIDENT AND CHIEF EXECUTIVE OFFICER — 1995
Lexacal Investment Corp.
West Vancouver, British Columbia

ROY G. DYCE
PRESIDENT AND CHIEF EXECUTIVE OFFICER — 1982
Pacific Northern Gas Ltd.
Coquitlam, British Columbia

DIANE M. FULTON [2,5]
EXECUTIVE DIRECTOR, INVESTMENTS — 2005
University of British Columbia
Faculty Pension Plan
Vancouver, British Columbia

HUGH C. MORRIS [1,3]
CHAIR — 1986
Eldorado Gold Corporation
Delta, British Columbia

DAVID J. ROWNTREE [3,5]
MANAGING DIRECTOR — 2003
Tricor Pacific Capital, Inc.
West Vancouver, British Columbia

DAVID G. UNRUH [3,4]
DIRECTOR — 2002
Westcoast Energy Inc.
and Union Gas Limited
West Vancouver, British Columbia

ARTHUR H. WILLMS [1,4,5]
DIRECTOR — 1983
Westcoast Energy Inc.
and Union Gas Limited
Vancouver, British Columbia

JANET P. WOODRUFF [2]
CHIEF FINANCIAL OFFICER AND VICE PRESIDENT SYSTEMS DEVELOPMENT AND PERFORMANCE — 2006
Vancouver Coastal Health
West Vancouver, British Columbia

1 Executive Committee
2 Audit Committee
3 Environment, Health and Safety Committee
4 Corporate Governance Committee
5 Human Resources and Compensation Committee

OFFICERS

R.F. Chase	Chair of the Board
R.G. Dyce	President and Chief Executive Officer
G.B. Weeres	Vice President, Operations and Engineering
E.A. Fletcher	Chief Financial Officer
C.P. Donohue	Director, Regulatory Affairs & Gas Supply
K.R. Teitge	Director, Corporate Development
K.E. Stark-Anderson	Secretary
C.P. Donohue	Assistant Secretary

INVESTOR INFORMATION

Stock Exchange, Securities and Symbols
Common and preferred shares are listed on the Toronto stock exchange under the symbols PNG and PNG.PR.A, respectively.

Annual and Special Meeting
The Annual and Special Meeting of the Shareholders of Pacific Northern Gas Ltd. will be held at the Hyatt Regency Vancouver Hotel, 655 Burrard Street, Stanley Room, Vancouver, British Columbia on April 27, 2006 at 10:30 a.m. (Pacific Daylight Time).

Annual Information Form
The Company's 2005 Annual Information Form, as filed with Canadian securities commissions, is available on our web site at www.png.ca.

Registrar and Transfer Agent
Computershare Investor Services Inc. (Vancouver, Calgary, Winnipeg, Toronto and Montreal).

Shareholder Assistance
If you are a registered shareholder and have questions regarding your account, please contact our transfer agent in writing, by telephone, fax or email at:

Computershare Investor Services Inc., 100 University Avenue, 9th Floor, Toronto, Ontario, Canada M5J 2Y1

Phone	Toll free North America 1.800.564.6253 International 514.982.7555
Fax	Toll free North America 1.866.249.7775 International 416.263.9524
Email	service@computershare.com
Internet	www.computershare.com – the Investors section offers enrolment for self-service account management for registered shareholders through *Investor Centre.*

If you hold your shares in a brokerage account (beneficial shareholder), questions should be directed to your broker on all administrative matters.

The Company's corporate and financial information, including quarterly reports, news releases, and utilities regulatory applications is available on our website at www.png.ca.

Corporate Governance
Please refer to the Company's Notice of 2006 Annual and Special Meeting of Common Shareholders and Management Information Circular for the Company's report on corporate governance. The Audit Committee of the Board of Directors has established an anonymous and confidential toll-free telephone number and web-based reporting tool for employees, contractors and others to call with respect to accounting irregularities and ethical violations. The telephone number is 1(800) 661.9675 and the web address is www.png-eweb.com.

Additional information relating to the Company is filed with securities regulators at www.sedar.com.

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PACIFIC NORTHERN GAS LTD.

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